BEFORE
THE PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA

DOCKET NOS. 2019-185-E and 2019-186-E

South Carolina Energy Freedom Act (H.3659) Proceeding to Establish Duke Energy Carolinas, LLC's and Duke Energy Progress LLC's Standard Offer Avoided Cost Methodologies, Form Contract Power Purchase Agreements, Commitment to Sell Forms, and Any Other Terms or Conditions Necessary (Includes Small Power Producers as Defined in 16 United States Code 796, as Amended) – S.C. Code Ann. Section 58-41-20(A)	**JOINT PROPOSED ORDER OF SOUTH CAROLINA SOLAR BUSINESS ALLIANCE AND JOHNSON DEVELOPMENT ASSOCIATES**

COME NOW Intervenors the South Carolina Solar Business Alliance ("SCSBA") and Johnson Development Associates ("JDA," and together with SCSBA, "Intervenors"), pursuant to the Hearing Examiner Directive issued in these consolidated dockets on September 19, 2019 (Order No. 2019-107-H), and file this Proposed Order.

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I. INTRODUCTION

This matter comes before the Public Service Commission of South Carolina ("Commission") on the initial review of the Duke Energy Progress LLC ("DEP") and Duke Energy Carolinas LLC ("DEC," and together with DEP, "Duke" or "the Companies") proposed standard offer, avoided cost methodologies, form contract power purchase agreements, commitment to sell forms, and other terms and conditions. The procedure followed by the Commission in this proceeding is set forth in S.C. Code Ann. § 58-41-20 (2019). In these dockets DEP and DEC seek approval of:

1. The Companies' application of the peaker methodology to calculate DEC's and DEP's avoided cost rates;

2. DEC's and DEP's updated Standard Offer, as now defined by S.C. Code Ann. § 58-41-10(15), which includes the Companies' respective Schedule PP (SC) Purchased Power tariffs ("Standard Offer Tariff" or "Schedule PP"), Terms and Conditions for the Purchase of Electric Power ("Standard Offer Terms and Conditions" or "Terms and Conditions"), and Standard Offer power purchase agreement ("Standard Offer PPA") available to all qualifying cogenerators and small power production facilities ("QFs") up to 2 megawatts ("MW") in size;

3. DEC's and DEP's form of power purchase agreement available to small power producer QFs that are not eligible for the Standard Offer ("Large QF PPA"); and

4. DEC's and DEP's notice of commitment to sell form ("Notice of Commitment Form").[1]

A. Notice and Intervention

By letters dated July 18, 2019, the Clerk's Office of the Commission instructed the Companies to publish a Notice of Hearing and Prefile Testimony Deadlines ("Notice") in newspapers of general circulation by July 29, 2019. The letters also instructed the Companies to provide Proof of Publication on or before August 12, 2019. The Notice indicated the nature of the

[1] Joint Application of Duke Energy Carolinas, LLC And Duke Energy Progress, LLC For Approval Of Standard Offer Avoided Cost Methodologies, Form Contract Power Purchase Agreements, Commitment To Sell Forms, And Other Related Terms And Conditions (Aug. 14, 2019) ("Joint Application") at 2.

proceeding and advised all parties desiring participation in the scheduled proceeding of the manner and time in which to file appropriate pleadings. On August 9, 2019, the Companies filed affidavits demonstrating that the Notice was duly published in accordance with the instructions set forth in the July 18, 2019 letter.

Petitions to Intervene were received from the South Carolina Energy Users Committee ("SCEUC"), the South Carolina Coastal Conservation League ("CCL") and the Southern Alliance for Clean Energy ("SACE"), the SCSBA, JDA, the South Carolina Department of Consumer Affairs ("SCDCA"), Ecoplexus, Inc. ("Ecoplexus"), and Walmart, Inc. ("Walmart"). The Petitions to Intervene of SCEUC, CCL, SACE, SCSBA, JDA, Ecoplexus, Walmart, and SCDCA were not opposed by Duke and no other parties sought to intervene in this proceeding. The South Carolina Office of Regulatory Staff ("ORS") is automatically a party pursuant to S.C. Code Ann. § 58-4-10(B) (2015).

II. STATUTORY STANDARDS

A. PURPA

The Public Utility Regulatory Policies Act, 16 U.S.C. § 824a-3 et seq., ("PURPA") was enacted in the U.S. by Congress in 1978 and was amended most recently in 2005. PURPA's principal goals included controlling power generation costs and ensuring long-term economic growth by reducing the nation's reliance on oil and gas. *Freehold Cogeneration Associates v. Board of Regulatory Commissioners of New Jersey*, 44 F.3d 1178 (3d Cir. 1995). Another key aim of the statute is to diversify the nation's electric energy supply by requiring electric utilities to purchase the output of small (i.e., less than 80 MW) independently owned alternative energy projects (referred to as "Qualifying Facilities" or "QFs") at the cost the utility would otherwise incur to generate power itself or purchase it from other sources – referred to as the utility's "avoided cost." PURPA was also intended to increase competition from independent power producers by reducing both fuel price risk and the cost of power.[2] Congress required the Federal Energy Regulatory Commission ("FERC") to establish broad guidance regarding the implementation of PURPA, which it has done through rulemaking and numerous orders, but left many of the details of PURPA implementation to the states, subject to compliance with FERC's directives.

There are several aspects of PURPA that are particularly relevant to this proceeding. First, the avoided cost construct was intended by Congress to leave ratepayers indifferent, from the standpoint of rates, whether the utility purchased power from QFs or procured it elsewhere. However, Congress specifically concluded that it was in the interest of utility ratepayers and the American public to promote QF development and diversify the generation portfolios of U.S. utilities. Since all development of capital-intensive electric generation facilities, including that by investor-owned utilities, requires certainty as to cost-recovery over a commercially reasonable period of time, "ratepayer indifference" in the context of PURPA's goal of promoting QF development does not, and cannot, mean zero risk to ratepayers – any more than utility self-built facilities result in zero risk to ratepayers. Rather, just as the General Assembly recognized in Act 62, it falls to state commissions such as this one to strike a reasonable balance between promoting QF development and protecting ratepayer interests.

Second, based on its view that smaller QFs would have a particularly difficult time negotiating with large monopoly utilities, FERC has required state commissions to adopt pre-approved avoided cost rates for QFs with a capacity of 100 kW or less – referred to as the "standard

[2] See, e.g., Public Utility Regulatory Policies Act, Joint Explanatory Statement of the Committee of Conference at 98, Report No. 95-1750 (Oct. 10, 1978).

offer" – and has given states the authority to extend the standard offer to larger QFs. 18 C.F.R. § 292.304(c). States also may establish standard PPA terms and conditions for any size QF.

Third, also out of a concern about utility bargaining power and potential recalcitrance, FERC has provided that a QF, in the absence of a formal contract, may obligate a utility to purchase its power at the current avoided cost rate by unequivocally committing itself to sell that output to the utility, thereby establishing a Legally Enforceable Obligation ("LEO") to sell power to the utility and for the utility to purchase that power. 18 C.F.R. § 292.304(d); *JD Wind 1, LLC*, 130 FERC ¶ 61,127, 61,631 (2010). Although states have considerable latitude in dictating the requirements to establish a LEO, they must observe certain minimum requirements established by FERC, and also cannot impose unreasonable obstacles on the formation of a LEO.

Finally, FERC understood that having the ability to obtain financing was critical to development of QF projects. Based on the understanding that reasonable certainty about long-term revenues was critical to obtaining financing, FERC provided in its regulations that QFs are entitled to enter into long-term contracts for the sale of energy and capacity at rates calculated at the time the contract or other legally enforceable obligation is incurred. 18 C.F.R. § 292.304(d). FERC has also ruled that PURPA PPAs must be of sufficient length to give the QF "reasonable opportunities to attract capital" for its project. *Windham Solar LLC & Allco Fin. Ltd.*, 157 FERC ¶ 61,134 at ¶ 8 (2016).

"Reasonable opportunities to attract capital" means that a QF must be able to obtain regularly-available, market-rate financing for the costs of developing, building, and operating their projects. This requires the Commission to consider types, terms, and providers of financing for QFs that are wholly different from the preferential financing that the utility enjoys by virtue of its monopoly status, history, and ability to rate-base the entirety of the cost of its generation facilities.[3] QF financing must not depend on a special program of the financing parties, the presence of a credit enhancement not broadly available, or other special circumstances. The terms and conditions of the QFs' PPAs also must meet standard underwriting criteria within the mainstream capital markets.

B. The South Carolina Energy Freedom Act

Act 62 made substantial reforms to South Carolina's implementation of PURPA as well as other aspects of the state's energy policy. The Commission disagrees with Duke's view that Act 62 did not, in fact, change the status quo or expand the authority of this Commission.[4] Act 62 is essentially a reset of utility regulation as it pertains to a range of issues related to the expansion of renewable energy generation and utility resource planning, and it provides this Commission with both increased direction and discretion in determining the most appropriate path forward for energy development in South Carolina. The Act makes clear that, in promoting South Carolina's policy of encouraging renewable energy, this Commission is directed to address all renewable energy issues in a fair and balanced manner that considers costs and benefits to all customers and establishes just and reasonable rates that reflect changes in the utility industry as a whole. Act 62 also recognizes and prioritizes increased competition and consumer choice within the state's electricity marketplace.

The primary issues covered in the Act include avoided cost methodologies, commercially reasonable contract terms and conditions, customer-sited generation, integrated resource planning, interconnection, community solar, commercial and industrial access to clean energy, integration

[3] Hearing Vol. 1 at 324.5-6 (Chilton Direct).
[4] Hearing Vol. 1 at 46.43 (Brown Direct).

of renewable energy, rate design, consumer protection, and increased Commission scrutiny of proposals for the construction of new major utility facilities. In implementing all aspects of the statute, the Commission "is directed to address all renewable energy issues in a fair and balanced manner, considering the costs and benefits to all customers of all programs and tariffs that relate to renewable energy and energy storage." S.C. Code Ann. § 58-41-05.

Key to this proceeding, the Commission is required by Act 62 to "open a docket for the purpose of establishing each electrical utility's standard offer, avoided cost methodologies, form contract power purchase agreements, commitment to sell forms, and any other terms or conditions necessary to implement this section." S.C. Code Ann. § 58-41-20(A). Any decisions by the commission shall be just and reasonable to the ratepayers of the electrical utility, in the public interest, consistent with PURPA and FERC's implementing regulations and orders, and nondiscriminatory to small power producers and shall strive to reduce the risk placed on the using and consuming public. *Id*.

The setting of avoided cost rates, as well as the terms and conditions that govern contractual obligations between utilities and small power producers ("SPPs"),[5] represents the foundation upon which large-scale solar must compete for market share against South Carolina's vertically-integrated monopoly utilities. The development of large-scale solar facilities is a capital- and time-intensive business that relies on fair and balanced treatment of SPPs within the regulatory arena in order to achieve success and meet the goals of Act 62.

[5] In this Proposed Order, the terms QF and SPP are used interchangeably, both in reference to small independent renewable energy power producers up to 80 MW that are eligible to sell energy and capacity to the Companies under PURPA and Act 62. Such facilities may also be referred to as "large-scale" or "utility-scale" solar facilities.

Given the multitude of issues before this Commission, it is critical to consider the cumulative impact of even small deviations from the just and reasonable, fair and balanced, and non-discriminatory requirements of Act 62. While any individual flaw or biased assumption in a utility's proposal might seem relatively inconsequential in isolation, the cumulative impact of many such flaws and biases could result in a virtual, if not total, elimination of large-scale solar development in the state. This result would frustrate the intent of the General Assembly when enacting Act 62, while also depriving utility customers of the myriad benefits that accompany solar energy development.

The Commission is also directed to "treat small power producers on a fair and equal footing with electrical utility-owned resources" by ensuring that:

> (1) Rates for the purchase of energy and capacity fully and accurately reflect the electrical utility's avoided costs;
> (2) Power purchase agreements ("PPAs") approved by the Commission are commercially reasonable and consistent with regulations and orders promulgated by FERC implementing PURPA; and
> (3) Each electrical utility's avoided cost methodology fairly accounts for costs avoided by the electrical utility or incurred by the electrical utility, including, but not limited to, energy, capacity, and ancillary services provided by or consumed by small power producers including those utilizing energy storage equipment.

Id.

Consistent with the language and intent of Act 62, this Commission must adopt just and reasonable rates, terms, and conditions that serve to "promote the state's policy of encouraging renewable energy." Artificially low avoided cost rates, inflated integration costs, and commercially unreasonable contractual terms and conditions would fail to satisfy the statutory requirements pertinent to this proceeding. Therefore, it is incumbent on this Commission to fairly deliberate on the credibility of the alternative analyses presented by intervening parties and determine whether those alternative analyses satisfy the requirements and serve to advance the goals of Act 62.

Act 62 was also intended to ensure that the Commission would be equipped to conduct a critical analysis of the utilities' avoided cost proposals, by requiring it to engage a third-party consultant or expert to conduct an independent analysis of those proposals and submit a report containing its independently-derived conclusions. This report is intended to be used by the Commission along with all other evidence to inform its ultimate decision. S.C. Code Ann. § 58-41-20(I). For this proceeding, the Commission retained Power Advisory LLC ("Power Advisory") on September 3rd to serve as the independent third-party consultant. Power Advisory is a management consulting firm focused on the North American electricity sector, and its lead consultant, John Dalton, has over thirty years of expertise as an electricity market analyst and policy consultant.[6] Power Advisory's responsibilities in this docket include drafting and review of PPAs, assessing renewable energy technology costs, evaluating the requirements to integrate variable output energy resources, and reviewing utility avoided cost. Power Advisory issued interrogatories and requests for production of documents to Duke and reviewed the Companies' responses, as well as all testimony filed in this docket. Power Advisory also monitored the hearing, and its final report to this Commission was issued on November 1st ("Power Advisory Report").

Finally, the legislature evidenced its concern with the transparency and reviewability of the utilities' avoided cost calculations, by requiring that "each electrical utility's avoided cost filing must be reasonably transparent so that underlying assumptions, data, and results can be independently reviewed and verified by the parties and the commission." S.C. Code Ann. § 58-41-20(J).

The responsible development of solar energy in South Carolina advances consumer preference, increases consumer choice, shields ratepayers from the inherent risks associated with

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[6] Power Advisory Report at 3.

utility-owned generation and investments, promotes local economic development, and furthers the goals of Act 62. Ultimately, the decisions made by this Commission in these proceedings will determine in large part whether or not these attributes of independently owned solar energy will materialize for the benefit of South Carolina as intended by the General Assembly.

C. The Obligation to Reduce Ratepayer Risk under Act 62

Act 62 requires that in deciding issues related to avoided cost, this Commission "shall strive to reduce the risk placed on the using and consuming public." S.C. Code Ann. § 58-41-20(A). The parties have different understandings of the significance of this provision, and in particular the scope of risks that the Commission must consider.

On the one hand, Duke interprets this reference to "risk" to refer solely to the risk that the avoided cost rates it pays to QFs under long-term PPAs could exceed the utility's actual avoided cost when that power is delivered, meaning that (in Duke's view) the utility and its customers will have "overpaid" for that QF power.[7] Because Act 62 provides a minimum contract duration of ten years for QFs, and Duke has no direct means of preventing QFs from exercising their PURPA rights to enter into contracts, Duke asks the Commission —in so many words—to set avoided cost rates as at the Companies' exceedingly low proposed rates while also acknowledging during cross examination that there is uncertainty about Duke's modeling assumptions and inputs used to calculate avoided cost.[8]

Intervenors, on the other hand, take a broader view of the risks that Act 62 requires this Commission to consider. Intervenors argue that the Commission should also consider the many risks to ratepayers that accompany utility-owned generation, like project cost-overruns and delays,

[7] Hearing Vol. 1 at 46.12-13 (Brown Direct).
[8] Hearing Vol. 1 at 134 (Snider Cross).

fuel volatility, waste-managements costs, and future environmental regulatory costs. In oral testimony, SCSBA Witness Davis agreed with Commissioner Williams' characterization of the General Assembly's intent in passing Act 62 as being, in part, to take some of the burden and risk off of ratepayers by providing them with an alternative to utility-owned energy generation.[9]

On consideration of the language and purposes of Act 62, the Commission concludes that Duke's interpretation of the "risk reduction" provision of the statute is unreasonably narrow. Act 62 is not exhaustive or limiting in describing the kinds of risk this Commission should consider. Nor does the context in which the Act was passed suggest that the General Assembly was exclusively (or even principally) concerned with the risks of long-term PURPA PPAs. To the contrary, the General Assembly specifically concluded that ten-year PURPA PPAs are in the interest of ratepayers. And given the recent history of investor-owned utility generation projects in South Carolina, it is implausible to suggest that the General Assembly would not have been concerned with the risks of those projects to ratepayers.

D. The Effective Date of the Avoided Cost Rates, Calculations, Terms, and other Provisions Approved in this Proceeding

Duke proposes that the Standard Offer Tariffs and avoided cost rates, charges and Terms and Conditions presented in the Companies' Application filed in these dockets apply to all QFs that established a LEO under PURPA after November 30, 2018, the date on which DEC and DEP filed an application for approval of new avoided cost rates in Docket No. 1995-1192-E.[10] The rationale offered by Duke is that the terms of the existing standard offer tariff (Schedule PP) approved by Order No. 2016-349 provided that those rates would only be available to QFs that established a LEO "on or before the filing date of proposed rates in the next avoided cost

[9] Hearing Vol. 2 at 811 lines 7-24.
[10] Joint Application at 9.

proceeding." According to Duke, establishing an effective date any later date than November 30, 2018, would result in the absence of long-term fixed avoided cost rates by which new Standard Offer QFs could sell power to the Companies pursuant to PURPA from November 30, 2018 until the later effective date of Schedule PP established in this proceeding.

However, Duke ignores this Commission's historic practice of making changes to avoided cost rates effective as of the next billing cycle after an Order approving the changes is issued. See, e.g., Order No. 2016-349 (May 12, 2016); Order No. 2013-183 (Mar. 29, 2013); Order No. 2013-184 (Mar. 29, 2013). This practice is consistent with S.C. Code Ann. § 58-27-860, which provides that proposed rate changes "may not be put into effect in full or in part until approved by the commission." Act 62 did not change this statutory requirement, and the statute certainly does not suggest retroactive application of any provision. To the contrary, it specifically provides that the statute "is not intended, and shall not be construed, to abrogate small power producers' rights under PURPA that existed prior to the effective date of the act." S.C. Code Ann. § 58-40-21(F)(1). It would also have been unnecessary for the Act to impose a six-month deadline for approval of the utilities' avoided cost proposals if the legislature had concluded that those rates, terms, and conditions could be given retroactive application. S.C. Code Ann. § 58-41-20(A).

The Commission acknowledges that this ruling means that the availability of the standard offer may have lapsed after November 30, 2018. However, PURPA only requires states to provide standard offer rates to Qualifying Facilities with a capacity of 100 kW or less, and the Commission is unaware of any project that size that has sought to contract with Duke under standard offer rates since November 30, 2018.[11]

[11] To the extent there were projects under 100 kW that established LEOs after November 30, 2018, the Commission determines that they would be entitled to Schedule PP rates, notwithstanding language in that tariff to the contrary.

III. HEARING

In order to consider the merits of this case, the Commission convened a hearing on this matter on October 21-22, 2019, with the Honorable Comer H. "Randy" Randall presiding. Duke was represented by Heather Shirley Smith, Esquire; Rebecca J. Dulin, Esquire; Frank R, Ellerbe, III, Esquire; E. Brett Breitschwerdt, Esquire; and Len S. Anthony, Esquire. SCEUC was represented by Scott Elliott, Esquire. CCL and SACE were represented by Stinson Woodward Ferguson, Esquire; J. Blanding Holman, IV, Esquire; Lauren Joy Bowen, Esquire; and Maia Danaid Hutt, Esquire. SCSBA was represented by Benjamin L. Snowden, Esquire; Weston Adams, III, Esquire; and Jeremy C. Hodges, Esquire. JDA was represented by James H. Goldin, Esquire. Ecoplexus was represented by Richard L. Whitt, Esquire. Walmart was represented by Carrie Harris Grundmann, Esquire. Nanette S. Edwards, Esquire; Andrew M. Bateman, Esquire; and Alexander W. Knowles, Esquire, represented ORS. In this Order, ORS, SCEUC, CCL, SACE, SCSBA, JDA, Ecoplexus, Walmart and Duke are collectively referred to as the "Parties" or sometimes individually as a "Party."

Duke presented the direct testimonies and exhibits of George V. Brown, Glen A. Snider, David B. Johnson, Steven B. Wheeler, and Nick Wintermantel. ORS presented the direct testimonies and exhibits of Brian Horii and Robert A. Lawyer. CCL and SACE presented the direct testimony and exhibits of Brendan Kirby and James F. Wilson. SCSBA presented the direct testimony and exhibits of Hamilton Davis, Jon Downey, Edward A. Burgess, and Steven J. Levitas. JDA presented the direct testimony of Rebecca Chilton. Ecoplexus, SCEUC, SCDCA and Walmart did not present witnesses at the hearing. In response to the direct testimony filed by CCL and SACE, SCSBA, JDA and ORS, Duke presented the rebuttal testimony and exhibits of Witnesses Brown, Snider, Johnson, Wheeler, Wintermantel, and John Samuel Holeman, III. In response to

Duke's rebuttal testimony, CCL and SACE filed surrebuttal testimony of Witnesses Kirby and Wilson; SCSBA filed surrebuttal testimony of Witnesses Davis, Downey, Burgess, and Levitas; JDA filed surrebuttal testimony of Witness Chilton; and ORS filed surrebuttal testimony of Witness Horii.

IV. REVIEW OF THE EVIDENCE AND EVIDENTIARY CONCLUSIONS

After hearing the evidence and testimony of the witnesses, the Commission reaches the following factual and legal conclusions:

A. Act 62 and Ratepayer Risk

Act 62 requires the Commission, in considering issues related to avoided cost, to "strive to reduce the risk placed on the using and consuming public." S.C. Code Ann. § 58-41-20(A). The parties take fundamentally different views of how this provision should inform the Commission's decision-making.

1.Duke Direct Testimony

Duke Witness Brown's testimony related to risk considerations pertinent to this proceeding is limited to a focus on the risk of overpayment to QFs if energy costs go down over the fixed term of a PPA.[12] To illustrate this potential risk to customers, Mr. Brown points to North Carolina, where a large number of QF PPAs were signed at avoided cost rates that are higher than Duke's proposed rates in this docket.[13] Mr. Brown claims that the difference between Duke's proposed avoided cost rates in this docket and the avoided cost rates reflected in prior QF PPAs represents an "overpayment" for energy and capacity that is ultimately passed along to ratepayers.[14] Mr.

[12] Hearing Vol. 1 at 46.11 (Brown Direct).
[13] *Id.* at 46.14.
[14] *Id.* at 46.16.

Brown goes on to identify three contributing components that create an overpayment risk for customers: (1) avoided cost rates, (2) length of contract, and (3) the volume of contracts.

2.SCSBA Direct Testimony

Although the SCSBA also recognizes and acknowledges the risk of "over-payment" for both PURPA and CPRE-style contracts if PPA rates are higher than the actual costs avoided by a utility, SCSBA witnesses also point out the risk associated with utility-owned generation and the requirements in Act 62 that suggest these risks should be taken into consideration during this proceeding. SCSBA Witness Davis testified that ratepayer risk also extends to utility development and ownership of other generating resources, against which SPPs provide a significant risk hedge.[15] Mr. Davis provides a comprehensive list of potential and actual risks associated with utility-owned generation that do not accompany SPP-owned generation resources, including ratepayer risk associated with fuel volatility for resources like natural gas, project abandonment costs as seen with the Summer and Lee nuclear reactors, and environmental regulatory costs as are now being collected from customers for coal ash management expenses.[16]

3.ORS Direct Testimony

ORS Witness Horii contends that to the extent avoided cost conditions reflect the cost conditions that exist when a contract is signed, combined with the regular updating of avoided cost as required by Act 62, there is little risk of overpayment to solar QFs.[17] ORS Witness Lawyer testified that Duke's proposed solar integration services charge represents a rate design that minimizes risk to customers by assigning integration costs directly to QFs.[18]

4.Duke Rebuttal Testimony

[15] Hearing Vol. 1 at 391.8 (Davis Direct).
[16] *Id.* at 391.13.
[17] Hearing Vol. 2 at 525.9 (Horii Direct).
[18] Hearing Vol. 2 at 532.5 (Lawyer Direct).

Duke Witness Brown revisits his discussion of ratepayer risk associated with long-term, fixed-price contracts and points to the FERC Notice of Proposed Rulemaking ("NOPR") as providing potential relief from these risks.[19] Mr. Brown then testifies that this Commission should limit contracts to the minimum length of time necessary for compliance with Act 62.[20] Mr. Brown also claims that long-term, fixed price contracts procured through competitive solicitations reduce risk to ratepayers.[21] Finally, Mr. Brown contends that a comparison of risk profiles between QF generation and utility-owned generation is "entirely inapplicable" to this proceeding[22] and that QFs do not mitigate the risk of construction cost overruns for utility-owned generation.[23]

5.SCSBA Surrebuttal Testimony

SCSBA Witness Burgess clarifies that, in contrast to claims by Duke, he is not recommending that avoided cost rates include a cost "adder" based on a reduction of risk to ratepayers.[24] Rather, Mr. Burgess's testimony illustrates the ratepayer risk that must be considered under Act 62 is not limited to QF contracts, as claimed by Duke, but also extends to utility-owned generation.[25] SCSBA Witness Davis maintains that SPPs provide a significant risk-hedge against the bevy of risks borne by ratepayers that flow from utility-owned generation and that Act 62 places these risks squarely in the purview of this Commission during this proceeding.[26] Mr. Davis also rejects Witness Brown's contention that risk-mitigation measures built into South Carolina's regulatory structure obviate the need for this Commission to consider those risks in these

[19] Rebuttal Testimony of George Brown at 8.
[20] *Id*. at 23.
[21] *Id*. at 24.
[22] *Id*. at 30.
[23] *Id*. at 33.
[24] Surrebuttal Testimony of Edward Burgess at 8.
[25] *Id*.
[26] Surrebuttal Testimony of Hamilton Davis at 15.

proceedings. Mr. Davis points out that the recent history of plant abandonments, mounting coal ash costs, and natural gas price volatility all contradict Mr. Brown's testimony on risk considerations in this proceeding.[27]

6.Testimony at the Hearing

ORS Witness Horii testified at the hearing that he does not have confidence in the accuracy of Duke's claimed overpayment calculations, nor does he expect natural gas prices to decline further in the future.[28]

Duke Witness Brown acknowledged that construction and operation of utility-owned generation exposes ratepayers to risks, such as overpayment, under-delivery and increased fuel costs, that can have an adverse economic impact on ratepayers.[29] Mr. Brown also acknowledged that these and other risks are communicated with shareholders and potential shareholders and lenders.[30] Further, Mr. Brown confirms that, in contrast to utility-owned generation, the QF bears the majority of risks associated with solar project development.[31]

SCSBA Witness Davis continues to acknowledge the overpayment risk that accompanies QF contracts, but stresses that risk exists within all aspects of the energy industry and is, in fact, greater when it comes to utility-built generation.[32] Mr. Davis points out that Act 62 explicitly requires this Commission to strive to reduce the risk placed on the using and consuming public, and that the statute does not limit the scope of the risk this Commission can or should consider. Rather, Act 62 explicitly requires that the Commission consider QF resources on fair and equal

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27 *Id*.
28 Hearing Vol. 2 at 596.
29 *Id*. at 654.
30 *Id*. at 660.
31 *Id*. at 670.
32 *Id*. at 799.

footing with utility-owned resources.[33] Mr. Davis also discusses the fact that Act 62 was adopted in the wake of the Summer and Lee abandonments and was motivated in part by a business-as-usual approach to utility-owned generation that was not serving the best interest of ratepayers. Further, Mr. Davis agreed with Commissioner Williams that it could be argued that Act 62 represented an attempt to shift risk away from ratepayers and onto QF developers by increasing QF development in South Carolina.[34]

Similarly, the operation of any generating unit over a long period of time creates risks that, for example, the costs of fuel for the unit will rise relative to other fuel types; operational costs such as environmental costs will increase over time.[35] These increased costs can rise to the level of making a utility-owned generation plant uneconomical. Mr. Brown agreed that in the case of a fixed-price long-term PURPA contract, the QF bears all project risks.[36]

7. **The Commission's Conclusions Regarding Act 62 and Ratepayer Risk**

A primary policy objective of Act 62 is to benefit the customers of South Carolina utilities. Among other things, Act 62 requires that in setting avoided cost rates, the Commission must "strive to reduce the risk placed on the using and consuming public." S.C. Code Ann. 58-41-20(A). Act 62 also requires that the Commission's decisions be just and reasonable, in the public interest, consistent with PURPA and FERC orders and regulations, and "treat small power producers on a fair and equal footing with electrical utility-owned resources."

In opening statements, Duke counsel claimed that the testimony of other parties that focus on the risk related to utility-owned generation is nothing more than rhetoric that is clouding the

[33] *Id*. at 800.
[34] *Id*. at 811.
[35] Hearing Vol. 2 at 655:4-657:22.
[36] Hearing Vol. 2 at 670:7-672:17, 673:2-675:6.

purpose of this proceeding and distracting from the issues that are before the Commission.[37] The Commission disagrees. Duke takes an unreasonably constrained view of the risks to be considered under Act 62. While all parties acknowledge the risk of overpayment if avoided cost rates are set too high, this Commission also agrees with the SCSBA that it is appropriate and necessary under Act 62 to consider the risks avoided by QF development.

When a utility purchases power under a long-term QF PPA rather than building a new generating unit, ratepayers are completely insulated from those risks, which are borne entirely by the QF.[38] The ratepayer pays only the energy and capacity value of the power actually produced by the QF.[39]

This Commission finds that the intent of the General Assembly in passing Act 62 was that a broad consideration of risk to ratepayers be taken into account during this proceeding. The plain language of the statute does not limit risk assessment to QF contracts, and the recent history of plant abandonments and mounting costs associated with coal ash management make a broader perspective on ratepayer risk appropriate.

As testified to by ORS Witness Horii[40] and reinforced by the Power Advisory Report[41], regular updating of avoided cost rates combined with the current historically low natural gas prices that heavily influence the avoided energy rates being considered in this proceeding, this Commission has determined that the risk to the ratepayer will be reduced and that there is little risk of overpayment to solar QFs.

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[37] Hearing Vol. 1 at 22.
[38] Hearing Vol. 1 at 401.8-10 (Downey Direct).
[39] Hearing Vol. 1 at 391.22-23 (Davis Direct).
[40] Hearing Vol. 2 at 528.8 (Horii Surrebuttal).
[41] Power Advisory Report at 7.

Similarly, this Commission also finds that QF solar insulates ratepayers from the multitude of risks associated with utility-owned generation. Unlike QF solar, increased costs associated with project delay and abandonment, environmental regulations, and fuel volatility are often passed along directly to utility customers. Having a larger portion of energy and capacity be provided by QF solar is a goal of Act 62 and satisfies this Commissions responsibility to reduce risk to ratepayers.

On consideration of these factors, the Commission finds that in the current environment of low avoided cost rates and low natural gas prices, fixed-price PURPA PPAs reduce, rather than increase, risk to ratepayers. In addition, contracts for terms of longer than ten (10) years may also result in a net decrease in ratepayer risk as compared to a business-as-usual approach to development of utility-owned generation.

B. Avoided Cost Calculations and Methodologies

Duke asks the Commission to approve its application of the peaker methodology to calculate DEC's and DEP's avoided cost rates, including rates for energy and capacity.[42]

1.General Issues

a. Avoided Cost and the "Zone of Reasonableness"

In his direct testimony, SCSBA Witness Burgess argues that the concept of a "zone of reasonableness" is relevant to this Commission's consideration of utility avoided cost determinations. This "zone of reasonableness" concept is essentially a sensitivity analysis that logically follows from the fact that some level of uncertainty is inherent and unavoidable in the models and forward-looking price projections used to calculate avoided cost.[43] Therefore, a range

[42] Joint Application at 2.
[43] Hearing Vol. 1 at 382.8, 328.12 (Burgess Direct).

of inputs, assumptions, and methodologies could be found to be reasonable when calculating avoided cost. This is plainly evident by the fact that Dominion Energy South Carolina and Duke Energy use two different Commission approved methodologies, the differential revenue requirement and peaker methods, to calculate avoided cost.

Duke Witness Snider characterizes the "zone of reasonableness" concept as "novel" and considers it "inappropriate and inconsistent with the standards established for setting avoided costs rates under PURPA and Act 62."[44] However, during cross examination by Duke, Mr. Burgess stressed that the "zone of reasonableness" is not meant to convey a narrow legal definition, rather this is a general concept that reflects the necessarily imprecise nature of predicting the future through avoided cost calculations. Mr. Snider agreed during cross-examination that there is "certainly" uncertainty about Duke's modeling assumptions and inputs used to calculate avoided cost and that the correct way to adjudicate each of the modeling inputs is to determine whether they are fair, just and reasonable.[45] This Commission agrees that avoided cost calculations are necessarily imprecise and that fair, just, and reasonable inputs should be used. This Commission also agrees that this imprecision creates a "zone of reasonableness" whereby competing alternatives for particular inputs could each be deemed fair, just and reasonable, and that Act 62's stated intent to encourage the development of renewable energy should influence the final decision from this Commission as to what inputs will be required for the calculation of avoided cost.

b. The Transparency of Duke's Avoided Cost Filings

[44] Hearing Vol. 2 at 630.14 (Snider Rebuttal).
[45] Hearing Vol. 1 at 134.

Act 62 requires that the utilities' "avoided cost filing must be reasonably transparent so that underlying assumptions, data, and results can be independently reviewed and verified by the parties and the commission."

As discussed below, SCSBA Witness Burgess raised concerns in his testimony about the transparency of the information Duke provided in support of its avoided cost calculations, both with its initial filings and in response to discovery requests. Witness Burgess also stated that Duke refused in discovery to provide the results of additional modeling runs using alternative assumptions as to certain inputs.[46] Because avoided cost is in large measure a modeling exercise using Duke's production cost models, such "sensitivity analyses" are often the only practical way to quantify the impact of certain assumptions on rates.[47]

In his Surrebuttal Testimony, Mr. Burgess recommends that Duke provide additional transparency regarding the following assumptions: (1) Detailed descriptions of must-run and

[46] Hearing Vol. 2 at 787.23 (Burgess Surrebuttal).

[47] The Commission notes that with regard to this and other gaps identified in the information provided by the utilities in support of their avoided cost calculations, Intervenors cannot necessarily be faulted for not filing motions to compel production of that information (as opposed to simply requesting it in discovery). All parties to this docket operated under significant time constraints to evaluate large volumes of complicated information, and to formulate reasoned responses to the other parties' filings. Moreover, the Commission notes that it may not be clear that there are gaps in information provided by the utilities until responses to discovery requests are received, and that propounding follow-up discovery requests and receiving responses may take several weeks. Furthermore, in any contested case – to say nothing of swiftly-moving litigation where dozens of complicated issues are in play – it may not be a prudent use of parties' limited resources to litigate motions to compel (which can themselves take weeks to resolve). Nor is it prudent for the Commission to encourage parties to future proceedings to file unnecessary motions to compel, lest they be faulted for not doing so. The Commission would vastly prefer that parties try to resolve disputes about discovery informally (which itself may be time-consuming process, especially when the parties are trying to act reasonably towards each other), and commends the parties for their efforts to resolve discovery disputes without filing motions to compel. In light of these factors, and in light of the transparency requirements of Act 62, the Commission believes it would be unreasonable to conclude that, if an Intervenor identifies gaps in information provided the utilities (especially in discovery), it must file a motion to compel or waive any right to complain about those gaps.

cycling restrictions and the rationale for including these; (2) Hourly data on when must-run units are operating; (3) Hourly data on pumped hydro dispatch in the base case and change case; and (4) Hourly data on the timing of individual unit starts. Given the significant proportion of hours with negative avoided costs, such information would enhance the transparency of the Companies' avoided cost filing.

Power Advisory characterized the Companies' filings as "reasonably transparent" in compliance with the statute, but observed that improvements to transparency can be made in future biennial avoided cost proceedings.[48]

ORS Witness Horii did not take issue with the transparency of the utilities' filings but noted that future proceedings would benefit from a longer time frame (while acknowledging the time constraints imposed by Act 62). He notes that for comparison, the proceedings in California that determine avoided costs and ratemaking, parties are provided with approximately four (4) months to prepare testimony after the utility application is filed, with rebuttal testimony from all parties due about three (3) months later. Other than the increased timeframe for parties to conduct analysis and develop positions, this timeframe also allows the utility more time to respond to data requests and provides all parties with more time to potentially settle any emerging issues.[49]

The Commission concludes that, in light of the novelty of many of Act 62's statutory requirements and the expedited time frames under which all parties were working, Duke reasonably complied with its transparency obligations under Act 62. Nonetheless, substantial improvements can be made to ensure greater transparency and integrity in the process going forward. Accordingly, prior to the opening of the next proceeding to consider Duke's avoided

[48] Power Advisory Report at 9.
[49] Hearing Vol. 2 at 525.5 (Horii Direct).

costs rates, calculations, and methodologies conducted under S.C. Code Ann. § 58-41-20, the Commission will solicit proposals from all interested parties on recommendations related to improved transparency, consistent with the requirements of Act 62.

2.Avoided Energy Costs

a. Duke Direct Testimony

Duke Witness Snider testifies concerning the Companies' use of the peaker methodology to estimate avoided energy costs. The peaker methodology is a widely accepted industry standard approach to quantifying avoided costs.[50] It is designed to ensure that purchases from new QF generators are not more expensive than the avoided capacity cost of a simple cycle combustion turbine ("CT") or "peaker" unit plus the utility's forecasted avoided system marginal energy cost. Duke Witness Snider testifies that "[t]his approach assumes…the variable marginal energy cost of running the system will produce a reasonable proxy for the marginal…energy costs that a utility avoids by purchasing power from a QF."[51]

The Companies used a production cost simulation model ("PROSYM") to estimate the hourly avoided energy costs of a fixed block of 100 MW that was assumed to be available throughout the year. The model is specified to reflect the Companies' generation resources including capacity ratings, outage rates, physical constraints (e.g., start times) and variable operating costs (i.e., fuel, environmental costs and variable operations and maintenance expenses). Hourly customer demand is also reflected, with the model dispatching generating units to meet hourly customer load at least cost. Witness Snider testified that in order to most accurately reflect the Companies' current estimates of DEC's and DEP's future capacity needs and projections of

[50] Hearing Vol. 1 at58.45 (Snider Direct).
[51] *Id*. at 58.10.

future costs that QFs can avoid, the Companies rely largely upon data and assumptions from the Companies' 2019 IRP Update.[52]

To project avoided energy costs the model is run for both a "Base Case" and a "Change Case", which reflects the addition of a 100 MW generator available in all hours. The difference in the hourly energy cost between the Base Case and the Change Case is the hourly avoided energy cost. The Companies then aggregated these hourly avoided energy cost values into nine energy price periods in each year from 2020 to 2029, with these annual values levelized to produce ten-year levelized avoided energy cost estimates, which are adjusted for losses recognizing the assumed interconnection voltage of the QF on the Companies' system, incremental working capital requirements and applicable excise taxes. The nine energy pricing periods are summer premium-peak, on-peak, and off-peak; winter premium-peak, on-peak (AM and PM), and off-peak; and shoulder-season on-peak and off-peak.

b. SCSBA Direct Testimony

SCSBA does not take issue with Duke's use of the peaker methodology to calculate avoided energy costs. However, SCSBA Witness Burgess offered testimony about several concerns regarding Duke's implementation of this methodology for its avoided energy calculations. Burgess testifies that these deficiencies in Duke's calculation methodologies render the proposed rates not accurate, just, or reasonable. These issues, as identified and described by Witness Burgess, include the following:

<u>Negative avoided cost values</u>: Witness Burgess opined that Duke's hourly modeling results show a significant fraction of hours that have negative avoided costs in the change case, despite the Base Case having positive marginal cost values in over 99% of hours. The presence of

[52] *Id*. at 58.16.

these negative values depresses the average avoided cost rates. Many of these negative avoided cost values occur during critical summer peak periods, when demand is particularly high and solar resources are available. One would naturally expect to see the highest avoided cost values during these periods. Witness Burgess testifies that the frequency of these negative values suggests deficiencies in Duke's modeling, such as assumptions that do not match reality.[53]

Rate structure and selection of pricing periods: Duke has proposed nine energy pricing periods for its avoided energy rates: summer premium-peak, on-peak, and off-peak; winter premium-peak, on-peak (AM and PM), and off-peak; and shoulder-season on-peak and off-peak. The choice of pricing periods has significant implications for avoided cost rates and, ultimately, QF revenues. Witness Burgess testified that Duke's proposed rate design arbitrarily reduces the avoided energy cost rate during several key solar QF production hours by averaging these hours with lower value hours.[54] Witness Burgess proposed a modified rate design that would send more accurate price signals to QFs and remove some of the bias, as required by Act 62, against solar QFs during summer mornings and mid-day periods in shoulder months.[55]

Combination of DEP Balancing Authority Areas: DEP's system includes two balancing authorities: DEP East and DEP West. DEP West is located entirely in North Carolina and generally has lower marginal energy costs than DEP East. Witness Burgess noted that, notwithstanding the fact that DEP's entire South Carolina service territory is in the DEP East balancing authority area, DEP's avoided energy cost values appear to combine model results from both the DEP East and DEP West systems. This may depress avoided energy rates for DEP.[56]

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[53] Hearing Vol. 1 at 282.23-28 (Burgess Direct).
[54] *Id*. at 282.37-43.
[55] *Id*. at 282.40-43.
[56] *Id*. at 282.34-36.

Large QF Calculation Methodology: Witness Burgess testified that Duke's method for calculating avoided energy costs rates for non-Standard Offer, Large QFs is not fully transparent, but appears to diverge from the methodology used to calculate rates for Standard Offer QFs.[57]

Environmental costs: Witness Burgess testified that Duke's avoided energy cost calculations do not adequately account for certain environmental costs of marginal generating units, in particular coal ash disposal costs.[58]

Hedging value of solar: Witness Burgess testified that Duke's avoided energy cost calculations do not reflect the fuel hedging value of solar QF resources, notwithstanding the fact that solar resource provide hedges against natural gas price increases that are likely to occur.[59]

c. ORS Testimony

ORS Witness Horii testified on direct that in his opinion the avoided energy costs and rate design were a reasonable result of the methodology used by the Companies, which he characterized as a variant of the Differential Revenue Requirements methodology.[60] Mr. Horii acknowledged at the hearing that he was not asked to, and did not, review the reasonableness of the 2019 IRPs on which Duke's avoided energy cost calculations relied.[61] Nor was he aware, when he conducted his analysis, of the accelerated retirement of coal units recently announced by DEC.[62]

d. Duke Rebuttal

In his rebuttal testimony, Duke Witness Snider testified that in his view, the Companies have accurately calculated their avoided energy cost rates, and in doing so, have accurately

[57] *Id*. at 282.30-32.
[58] *Id*. at 282.32-34.
[59] *Id*. at 282.29-30.
[60] Hearing Vol. 2 at 525.9 (Horii Direct).
[61] Hearing Vol. 2 at 538.
[62] *Id*.

modeled for "real world" system operations; accurately modeled marginal avoidable resources for DEP as a single regulated utility and Balancing Authority; appropriately excluded a fuel hedge from avoided energy rates, as avoided energy rates are limited to real costs actually being avoided; and appropriately included environmental costs in calculating DEC's and DEP's avoided energy rates. He further testified that in his view, it is appropriate to apply a project-specific solar generation profile for large QFs ineligible for the standard offer in calculating such QFs' energy rates. Witness Snider dismissed SCSBA Witness Burgess' arguments against the Companies' energy rate design, arguing that the design provides sufficient seasonal and hourly granularity and appropriate price signals that incentivize QFs to maximize output during times when energy has the most value to the Companies and customers.[63]

e. SCSBA Surrebuttal

SCSBA Witness Burgess provided surrebuttal testimony responding to several issues discussed by Duke's witnesses on rebuttal. Burgess responded to Duke's argument that its methodological choices are sound because they are consistent with those already used in its integrated resource plan, noting that the IRP itself could be methodologically flawed, that it was not provided to the other parties until well after these proceedings were already underway, and that *after* submitting its avoided cost filings in this case, Duke announced the accelerated retirement of three coal units with a total combined capacity of approximately 1 gigawatt ("GW"), which retirements were not reflected in the company's avoided cost calculations.[64] Burgess also noted that the IRP did not reflect recent guidance from the NCUC or the IRP sufficiency requirements of Act 62.[65]

[63] Hearing Vol. 2 at 630.4 (Snider Rebuttal).
[64] Hearing Vol. 2 at 787.6-7 (Burgess Surrebuttal).
[65] *Id*.

As to avoided energy values, Burgess acknowledged that Duke's argument that negative avoided cost values were the result of changes in the timing of unit startups made conceptual sense, but that it was impossible to verify this claim given that Duke did not provide sufficient data on hourly unit starts or startup costs.[66]

Burgess additionally expressed concern about whether the inclusion of coal units with cycling and must-run restrictions in the model is appropriate, as this could have significant effects on model results. This is because if must-run units are (appropriately) not included in the model, then the marginal gas unit that is displaced by QF capacity would more likely be a higher-cost, less-efficient gas unit. Duke did not provide information on the cycling and must-run restrictions of its coal units along with its avoided cost calculations. This issue is of additional concern because the coal units subject to accelerated retirement (as discussed above) are subject to these restrictions, and so failing to reflect their accelerated retirement in Duke's resource plan would have negative impacts on avoided cost calculations.[67]

Although he was unable to precisely quantify the impact of these issues on avoided energy values, Witness Burgess recommended that Duke provide additional data and transparency on the following issues:

- Detailed descriptions of must-run and cycling restrictions and the rationale for including these;
- Hourly data on when must-run units are operating;
- Hourly data on pumped hydro dispatch in the base case and change case; and
- Hourly data on the timing of individual unit starts.[68]

[66] *Id*. at 787.11-12.
[67] *Id*.
[68] *Id*. at 787.14.

Witness Burgess also recommended that Duke's model be rerun without the must-run designation for each of the coal units included as a sensitivity analysis to determine their effect on avoided energy costs.

With regard to Duke's response to concerns regarding the difference in marginal units for the DEP-East and DEP-West balancing authority areas, Witness Burgess testified that even given the existence of firm transmission interconnects between DEP-East and DEP-West, there may be times when that transmission capacity reaches its limit and the two areas have different marginal units. Mr. Burgess did not recommend a specific change to avoided cost based on this phenomenon, but recommended that, in the interest of better understanding this issue, Duke calculate avoided cost for each balancing authority area separately.[69]

With regard to rate design, Witness Burgess disagreed with Duke's characterization of SCSBA's initial proposal as being too focused on the specific operating characteristics of solar QFs, ignoring Duke's proposed design which intended to offer higher prices during times of higher value; and not being administratively manageable.[70] Witness Burgess noted that SCSBA's proposed time periods are agnostic as to technology, and are nearly identical to Duke's except that they provide additional granularity (and therefore accuracy) be breaking two of Duke's proposed time periods into two parts. This approach provides better granularity in pricing and less averaging of values, and it is not appreciably more difficult to administer than Duke's proposal. In Exhibit 2 to his Surrebuttal Testimony (Hearing Exhibit 25), Witness Burgess proposes the following pricing periods and energy rates for DEC:[71]

[69] *Id*. at 787.15.
[70] *Id*. at 787.16.
[71] Witness Burgess did not propose alternative time periods for DEP.

DEC: (highlights indicate modifications)

DEC	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Summer (Jun-Sep)	Off							On (AM)					On (PM)				Premium				On (PM)		Off	
Winter (Dec-Feb)	Off					On (AM)	Premium			On (AM)	Off							On (PM)					Off	
Shoulder (Remaining)	Off						On				Midday						On							Off

Period	Cents/kWh
1_DEC_Summer_Prem-Peak	4.58
2_DEC_Summer_PM-Peak	4.48
3_DEC_Summer_OffPeak	2.49
4_DEC_Winter_ Prem-Peak	5.04
5_DEC_Winter_ AM-Peak	4.61
6_DEC_Winter_ PM-Peak	4.15
7_DEC_Winter_ OffPeak	2.70
8_DEC_Shoulder_Peak	3.39
9_DEC_Shoulder_OffPeak	2.13
Summer AM Peak (New)	2.95
Shoulder Midday (New)	2.77

Witness Burgess also notes Duke's concession that its technology-specific approach for avoided costs is not appropriate for facilities that include storage, but notes that Duke has failed to provide any solution for this problem, instead supporting the application of a solar-specific generation profile even to solar QFs with storage.[72]

f. Consultant's Evaluation of Duke's Avoided Energy Calculations

With regard to the negative avoided energy values noted by SCSBA Witness Burgess, Power Advisory agreed that "these negative values significantly affect the avoided costs available

[72] *Id*. at 787.18.

to solar QFs" but did not draw any conclusions about whether those impacts are legitimate. However, Power Advisory did note, based on the testimony of Duke Witness Holeman, that the operational constraints driving those negative avoided cost periods could be mitigated with additional dispatch of solar resources, which can be provided by CPRE-style dispatchable solar contracts. The Consultant went on to state that "Power Advisory believes that there are potential savings from such operating flexibility that could benefit customers and QFs and make it easier to operate the Companies system, which have not been adequately acknowledged."[73]

With regard to accelerated coal unit retirements, the Consultant noted that "the high proportion of hours with negative avoided energy costs" is likely associated with the continuing operation of inflexible coal plants" and that the early retirement of those plants could reduce the proportion of those negative cost hours. Power Advisory could not quantify the impacts of the accelerated retirements on avoided energy costs, but recommended that the Commission direct utility companies, in the future, to base their avoided cost analyses on best available information that reflects anticipated unit retirements.[74]

With regard to Duke's selection of pricing periods, the Consultant noted that the selection of pricing periods can bias results, and conducted an analysis suggesting that Duke's selection of pricing periods resulted in underpayment of solar QFs in DEC and overpayment under DEP's rates. The Consultant further recommended "that the Commission direct the Companies to provide appropriate analytical support for their avoided cost periods in subsequent filings."[75]

g. The Commission's Conclusions Regarding Avoided Energy Costs

On consideration of the evidence, the Commission draws the following conclusions.

[73] Power Advisory Report at 13.
[74] *Id*. at 14.
[75] *Id*. at 17.

<u>Rate structure and selection of pricing periods.</u> It is undisputed that the selection of pricing periods has a significant impact on avoided cost rates, especially when low-cost periods are averaged with high-cost periods. With respect to generators like solar QFs that have little or no ability to respond to price signals, this can result in significant negative bias. The Commission is persuaded by SCSBA Witness Burgess's testimony that Duke's pricing periods are negatively biased against solar QFs in DEC territory, and that SCSBA's proposed pricing periods represent a reasonable alternative that provides better granularity in pricing and less averaging of values, without significantly increasing administrative burdens on Duke or on QFs. Accordingly, the Commission will approve revised energy rates for DEC with these pricing periods.

<u>Negative avoided cost values</u>. The Commission agrees with SCSBA Witness Burgess that the prevalence of negative avoided cost values in Duke's analysis is troublesome, given the significant impact of these negative avoided cost values on avoided energy costs. Although the parties agree that negative avoided cost values may be legitimately caused by shifting unit start times and must-run unit restrictions, the Commission is concerned that unrealistic or outdated assumptions on Duke's coal units may depress avoided costs. However, in the absence of specific information and additional analysis from Duke concerning must-run unit designations and coal unit retirement schedules, the Commission is unable to determine an updated avoided energy cost rate at this time. Although any adjustment to avoided cost rates cannot be determined at this time, in any future proceedings Duke must provide that information so that its calculations can be appropriately evaluated. And notwithstanding Mr. Snider's speculation at the hearing, the Commission is persuaded by Mr. Burgess's and Power Advisory's opinions that Duke's failure to reflect the accelerated retirement of coal plants in its IRP and avoided cost calculations would

likely result in a greater proportion of hours with negative avoided energy costs, and thus lower overall avoided energy costs.

Combination of DEP-East and DEP-West Balancing Authority Areas: Although there is no direct evidence on which the Commission can conclude whether DEP's calculation of avoided energy costs assuming a single Balancing Authority Area had an impact on avoided energy rates, the Commission is persuaded by Mr. Burgess's testimony that a more location-specific analysis merits further consideration. The Commission will require DEP, in the next avoided cost proceeding, to include a quantitative demonstration, including but not limited to a locational sensitivity analysis, to determine whether its approach to this issue impacts avoided energy costs. The Commission is not persuaded by Power Advisory's opinion that higher energy costs due to transmission congestion only pertain to competitive electricity markets and cannot arise in regulated electric utility systems.

Large QF Calculation Methodology. The concerns raised by SCSBA Witness Burgess about Duke's proposal to use project-specific production profiles for negotiated QF rates appear to be rooted more in transparency and "fit" than in the resulting rates themselves. The Commission concludes that, although Duke's proposal to use project-specific profiles is reasonable, SCSBA's concerns are legitimate and are consistent with Act 62's requirement (which was not specific to Standard Offer rates) that avoided cost calculations be reasonably transparent. Accordingly, Duke shall, at the request of a Large QF seeking to negotiate rates, provide any information about its rate calculations reasonably requested by the QF, including but not limited to the production profile and natural gas cost projections relied on by the utility in calculating the negotiated rate.

Environmental costs and hedge value. The Commission is persuaded by Intervenors' testimony that avoided energy rates should factor in coal ash management costs (though only on a prospective basis). Although there is insufficient evidence concerning the quantitative impact of those factors for the Commission to approve a specific adjustment to Standard Offer rates, the Commission will require DEC and DEP to incorporate that adjustment in its methodology for calculating negotiated rates, as well as in avoided cost proposals in subsequent proceedings.

There is also ample evidence that QF contracts provide additional value in the form of a hedge against rising natural gas prices. ORS Witness Horii, SCSBA Witnesses Burgess and Davis, JDA Witness Chilton, and Power Advisory all note that natural gas prices are near historic lows and are expected to rebound.[76] Duke Witness Snider testified at the hearing that Duke engages in some hedging against natural gas prices by procuring some gas via ten-year forward contracts, and also acknowledged that long-term fixed price PPAs do provide some hedge value.[77] Accordingly, the Commission will require Duke to incorporate a hedge value for solar in its methodology for calculating negotiated rates, as well as in avoided cost proposals in subsequent proceedings.

Conclusion as to Standard Offer energy rates. As noted above, Intervenors' testimony highlights a number of methodological flaws with Duke's avoided energy cost calculations. The effects of some can be clearly quantified without much further analysis, while others require Duke to conduct additional production cost modeling to be precisely quantified. However, the Commission concludes that the avoided energy pricing periods and rates proposed by SCSBA Witness Burgess represent reasonable estimates of avoided energy costs for purposes of the Standard Offer, and hereby approves those rates for inclusion in the Standard Offer for DEC.

3.Avoided Capacity Costs

a. Duke Testimony

[76] *See,* Hearing Vol. 1 at 391.8-9 (Burgess Surrebuttal); Hearing Vol. 1 at 391.11 (Davis Direct); Hearing Vol. 1 at 334.7 (Chilton Direct); Hearing Vol. 2 at 547; Power Advisory Report at 9.
[77] Hearing Vol. 1 at 206.

DEC and DEP use the peaker methodology to estimate the avoided capacity cost. Duke Witness Snider testifies that "This approach assumes that when a utility's generating system is operating at equilibrium, the installed fixed capacity cost of a simple-cycle combustion turbine ("CT") generating unit (a "peaker") plus the variable marginal energy cost of running the system will produce a reasonable proxy for the marginal capacity and energy costs that a utility avoids by purchasing power from a QF."[78] Mr. Snider notes that the Companies have consistently used the peaker methodology to forecast avoided energy and capacity costs and that the methodology has widespread acceptance.

Witness Snider further testifies that the peaker methodology implicitly assumes that peakers or simple-cycle combustion turbines represent ideal form of generation addition to meet future capacity needs. DEC & DEP's most recent IRP indicates that the most immediate utility sponsored capacity additions will be combined cycle gas turbines ("CCGTs") and CTs.[79] For the ten-year term of the Companies' avoided cost forecast, DEP's IRP proposes the development of a 1,341 MW CCGT in 2025 and an additional 1,341 MW CCGT in 2027, with 470 MW of CTs in 2028 and 1,880 MW in 2029. DEC's IRP specifies a 470 MW CT in 2026 and a 1,341 MW CCGT in 2028.

DEP's most immediate capacity need is addressed by two CCGTs, suggesting that these are a better fit, with the incremental capital cost of the CCGT offset by additional energy savings produced by the CCGT's lower heat rate. DEC's most immediate capacity need is addressed by a CT, with a larger CCGT added two years later.

[78] Hearing Vol. 1 at 58.10 (Snider Direct).
[79] DEP/DEC, "Integrated Resource Plan Update Report 2019," September 2019.

Duke also proposes a change to its seasonal allocation of capacity values. Duke proposes to allocate 100% of its capacity need to winter in DEP and 90% of its capacity need to winter in DEC.

b. SCSBA Direct Testimony

Intervenors SCSBA and JDA do not take issue with Duke's use of the peaker methodology to calculate avoided capacity costs. However, SCSBA Witness Burgess testifies that, in his opinion, there are several deficiencies in Duke's calculation methodologies which render the proposed rates not accurate, just, or reasonable. These include the following:

Seasonal Capacity Allocation. Duke proposes to allocate 100% of its capacity need to winter in DEP and 90% of its capacity need to winter in DEC. Witness Burgess testified that, in his opinion, Duke's seasonally weighted allocation of capacity value is overly skewed towards winter mornings versus summer afternoons, which is inconsistent with the high number of peak load hours Duke has during summer months. Duke's proposed seasonal allocation weightings significantly understate the capacity value that solar QFs provide to Duke in summer months where Duke experiences the vast majority of its peak load hours every year and improperly limit avoided capacity payments available to solar QFs.[80] Witness Burgess testifies that, in his, opinion, these seasonal weightings are based on flawed studies commissioned by Duke and performed by Astrapé, including improper assumptions regarding load forecasts, demand response, neighboring utility load and support, and seasonal assumptions for forced outage rates and planned maintenance.[81]

[80] Hearing Vol. 1 at 382.46-47 (Burgess Direct).
[81] *Id*. at 47-52.

Capital Cost Assumptions for Avoided Unit. Witness Burgess criticizes Duke's choice of the hypothetical combustion turbine ("CT") unit that it uses to establish avoided capacity costs under the peaker method significantly depresses avoided capacity costs. According to Witness Burgess, Duke has chosen the lowest-cost peaking unit in the Energy Information Administration's predetermined list of potential generation technologies and, in addition, has applied an inappropriate "economies of scale" factor which further reduces the avoided capacity rate.[82] Burgess testifies that Duke's CT unit choice does not necessarily reflect the next peaking unit that Duke will ultimately select to meet future peak demand, including available units that are more efficient and flexible but have higher capital costs.[83] Witness Burgess recommends that Duke be required to apply a CT cost assumption that represents a midpoint between Duke's proposed CT unit choice and the cost of a more efficient and flexible unit (including avoided transmission system upgrade costs)[84], and that Duke remove its inappropriate economies of scale factor.[85]

Near-term capacity values. Witness Burgess challenges DEC's assumption that QFs provide zero capacity value from 2020 to 2026, as well as DEC and DEP's assumptions that QFs provide zero capacity value after 2029. Witness Burgess proposes an alternative calculation of Duke's avoided capacity costs based on his revised assumptions.

Timing of Capacity Value Based on IRP: Witness Burgess calls into question Duke's treatment of near-term capacity value for DEC, which also inappropriately reduces avoided capacity rates. Specifically, he challenges DEC's assertion that its first "capacity need" is not until 2026 inappropriately assumes that each QF provides zero capacity value from 2020 to 2026, and

[82] *Id.* at 55.
[83] *Id.* at 56-58.
[84] *Id.* at 59-60.
[85] *Id.* at 58.

again after 2029.[86] Duke links its finding of capacity need to its IRP, but it does not account for regular bilateral sales and purchases of energy and capacity with other load serving utilities.[87] QFs can avoid the need for Duke to engage in certain short-term market capacity transactions, and this avoided cost should be reflected in avoided capacity rates.[88] DEC's assumption that there is no capacity value from QFs past 2029 is also flawed because it assumes that a QF with a ten year contract will no longer provide capacity value to the utility after that contract expires.[89] Burgess testifies that existing QFs will provide a meaningful "option value" because they have no fuel costs, no fuel transport costs, minimal O&M costs, and the cost to recontract with a QF for capacity would likely be very low compared to other options. Burgess recommends that Duke be required to include capacity value prior to 2026 for DEC and to recognize the value from QFs past 2029.[90]

c. CCL and SACE Testimony

SACE and CCL Witness James Wilson's direct testimony and expert report critiqued Duke Energy's propose Schedule PP avoided capacity credits and seasonal and hourly structures.[91] Witness Wilson's analysis demonstrated that DEP's proposed 100% winter 0% summer capacity payment allocation and DEC's proposed 90% winter 10% allocation significantly undervalues the capacity contributions of solar QFs.[92] Witness Wilson's direct testimony and report explained that the Companies' proposed seasonal capacity allocation were based on flawed assumptions contained in DEC and DEP's Solar Capacity Value Study and 2016 resource adequacy studies.[93]

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[86] *Id*. at 62.
[87] *Id*. at 62-63
[88] *Id*. at 63-65.
[89] *Id*. at 66.
[90] *Id*. at 67-69.
[91] Hearing Vol. 2 at 495.1-8 (Wilson Direct).
[92] *Id*. at 495.4-5.
[93] *Id*. at 495.6.

Witness Wilson's testimony also discussed the North Carolina Utilities Commission's ("NCUC") recent Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, Docket No. E-100 Sub 157 ("2018 NC IRP Order"), which declined to accept the load forecast and reserve margin assumptions and models also employed by the Companies' in this proceeding.[94] Witness Wilson recommended that the Companies' avoided capacity rates be rejected and more balanced seasonal weightings be developed and approved.[95]

During the evidentiary hearing Witness Wilson also discussed his experience with the development of resource adequacy studies in other jurisdictions including PJM.[96] Mr. Wilson described the more robust stakeholder process that other utilities utilize, including receiving input from stakeholders and running extensive sensitives in order to increase confidence in the results of the study.[97] Witness Wilson recommended that the Companies engage in a process of this type for future resource adequacy studies, the results of which are applied both in the context of the Companies' IRPs and in the calculation of avoided cost rates.

d. ORS Testimony

ORS Witness Horii recommended that DEC make two changes to its avoided capacity cost calculations: (1) Increase the Fixed Charge Rate for a CT; and (2) revise its seasonal allocation of capacity value.[98]

With respect to the first issue, Witness Horii testified that Duke's use of a 35-year economic life for the CT, rather than a 20-year economic life for the CT that is more commonly used, spread

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[94] *Id*. at 495.5
[95] *Id*. at 495.8.
[96] *Id*. at 505-507.
[97] *Id*.
[98] Hearing Vol. 2 at 525.13 (Horii Direct).

the capital-related costs of the CT over an excessive number of years and artificially lowers the estimate of costs that would need to be collected in each year for the CT owner.[99] Using a more reasonable 20-year economic life would increase avoided capacity costs by 29%.

With respect to the second issue, Witness Horii testified that although DEC correctly seasonal capacity costs based on the relative Loss of Load Expectation ("LOLE") in each time period, it is unreasonable for DEC to use LOLEs based on 3,500 megawatts ("MW") of assumed solar penetration on the DEC system. This is far in excess of the approximately 840 MW of solar currently on DEC's system results in shifting the need for system capacity away from the hours when installed solar is generating.[100]

Witness Horii recommended seasonal capacity allocation factors for relevant time periods as follows:

- Summer: 40%
- Winter morning: 48%
- Winter evening: 12%

Witness Horii recommended that the commission approve the following avoided capacity rates for DEC:

Summer on-peak (¢/kWh)	Winter AM on-peak (¢/kWh)	Winter PM on-peak (¢/kWh)
4.40	3.60	0.90

Witness Horii made similar critiques of DEP's avoided capacity calculations, and recommended adoption of the following rates for distribution projects:[101]

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[99] *Id*. at 525.13-14.
[100] Hearing Vol. 2 at 525.15 (Horii Direct).
[101] *Id*. at 525.18.

	Summer On-Peak	Winter AM On-Peak	Winter PM On-Peak
DEP Proposed Variable Credit (¢/kWh) **E3 Variable Credit (¢/kWh)**	0 **0.29**	10.82 **13.69**	4.64 **5.95**
DEP Proposed 5-year Fixed Credit (¢/kWh) **E3 5-year Fixed Credit (¢/kWh)**	0 **0.30**	11.03 **13.95**	4.73 **6.07**
DEP Proposed ten-year Fixed Credit(¢/kWh) **E3 ten-year Fixed Credit(¢/kWh)**	0 **0.30**	11.36 **14.37**	4.87 **6.25**

ORS Witness Horii testified that it was reasonable for Duke to rely on its 2019 IRPs in conducting its avoided capacity calculations.[102] However, he acknowledged at the hearing that he was not asked to, and did not, review the reasonableness of the 2019 IRPs.[103] Nor was he aware, when he conducted his analysis, of the accelerated retirement of coal units recently announced by DEC.[104]

e. Duke Rebuttal Testimony

In his Surrebuttal testimony, Duke Witness Snider responds to intervenors critiques and defends Duke's avoided capacity calculations as reasonable. He dismisses SCSBA Witness Burgess' recommended adjustments to the avoided capacity cost as erroneous and unreasonable, arguing that the Companies used the appropriate CT technology consistent with industry standards, appropriately adjusted for economies of scale to accurately calculate the capital cost for a new peaker, and determined the Companies' first year of need and corresponding assumed capacity value based upon DEC's and DEP's most recent IRPs.[105] He rejects SCSBA's, ORS's, and CCL/SACE's critiques of Duke's seasonal capacity allocations.[106]

[102] *Id.* at 525.11:17-525.12:3 (Horii Direct).
[103] Hearing Vol. 2 at 537-538.
[104] *Id.*
[105] Hearing Vol. 2 at 630.4 (Snider Rebuttal).
[106] *Id.* at 630.4-630.5.

a. ORS Surrebuttal

In his Surrebuttal testimony, ORS Witness Horii disagreed with Duke Witness Snider's claim that as 35-year useful CT life is appropriate for avoided capacity calculations, because the Companies failed to include appropriate fixed operating and maintenance ("FOM") costs as part of the total fixed costs 1 for a CT. If the Companies' goal is for avoided capacity costs to be consistent with the IRPs, the Companies should have included costs of major maintenance overhauls in FOM costs as part of the total fixed costs of a CT. Simply put, a CT cannot operate for 35 years unless it undergoes expensive overhaul work, the cost of which would need to be reflected in avoided capacity costs.[107] Horii further testified that it was inappropriate for the company to include FOM costs in its avoided energy calculations instead of its capacity calculations, and that factoring in FOM costs that was "essentially makes those costs disappear."[108]

Witness Horii also disagreed with Duke's assertion that basing its seasonal allocation on anything other than the "Tranche 4" level of solar penetration would result in "double counting" and "overpayment" for solar QF capacity.[109] He clarified that Act 62 requires that avoided cost calculations be based on current conditions, rather than hypothetical future conditions. This would not result in any over-payment risk, in part because avoided costs will be regularly updated.[110] However, Witness Horii did provide a revised seasonal allocation that included the amount of solar procured with signed CPRE contracts.[111]

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[107] Hearing Vol. 2 at 528.2-3 (Horii Surrebuttal).
[108] *Id*.
[109] *Id*. at 528.7-8.
[110] *Id*.
[111] *Id*. at 528.10.

Witness Horii recommended that the Commission approve the following capacity values for DEC, based on a 20-year CT useful life:[112]

	Summe r On-	Winter AM On-	Winter PM On-
DEC Proposed (¢/kWh)	0.86	3.99	1.29
E3 Surrebuttal (¢/kWh)	**3.30**	**3.94**	**1.31**

As with avoided energy costs, Witness Horii testified that he was unaware of the accelerated retirement of coal units by DEC when he conducted his analysis, but he agreed that the accelerated retirement of those units could have an impact on avoided capacity costs that would need to be analyzed to be understood.[113]

b. SCSBA Surrebuttal Testimony

As to avoided capacity costs, Witness Burgess rebutted Duke's assertion that solar QFs have "little impact" on a Duke's ability to avoided future capacity needs, particularly where a solar QF is able to add a storage facility.[114] Witness Burgess further notes that Duke's use of infrastructure costs for a four-unit CT site is inconsistent with the Companies' plans (as expressed in their IRPs) to build new CTs in blocks of two rather than four.[115] This means that a four-unit plant is not reflective of the utilities' own planning processes. To ensure that capital costs for CTs are fairly accounted for in avoided cost calculations, Witness Burgess recommends that the Commission adopt a cap on rate recovery for future utility-owned generation, based on the level of capital costs assumed in its avoided cost calculations. This would ensure that both utility-owned

[112] *Id*. at 528.11, 528.15.
[113] Hearing Vol. 2 at 538:13-540:3.
[114] Hearing Vol. 2 at 787.3 (Burgess Surrebuttal).
[115] Id. at 787.18-19.

generation and competitive third-party generation (in the form of QFs) are provided an equivalent level of compensation for providing capacity to Duke's customers.

Witness Burgess also disagreed with Duke's claim that transmission interconnection costs are already fully included in the peaker capital costs in all cases, noting that the EIA documentation Duke relies on specifically does not include significant transmission system upgrades, which are often required for utility projects.[116]

Witness Burgess also provided an updated calculation for seasonal allocation of capacity value, which responds to Duke's concerns that he "did not take into account the impact of must-take solar output," "incorrectly included an extremely broad number of hours by using the 'top 5% of load hours."[117]

Finally, Witness Burgess's Surrebuttal Testimony provided a set of alternative avoided capacity rate proposals reflecting Mr. Burgess's analysis of the impact of the methodological flaws in Duke's avoided capacity calculations.[118]

c. Consultant's Evaluation of Duke's Avoided Capacity Calculations

Power Advisory identified several issues with the Companies' avoided capacity calculations. Power Advisory agreed with SCSBA Witness Burgess that the accelerated retirement of coal units would likely impact capacity costs, and disagreed with Duke Witness Snider's claim (on cross-examination) that the effect of those retirements would be to drive avoided energy costs down.[119] Power Advisory recommended that DEC's avoided capacity cost be adjusted to reflect a one-year acceleration of the year in which capacity is required to 2025.

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116 *Id*. at 787.19.
117 *Id*. at 787.20.
118 Hearing Ex. 25.
119 Power Advisory Report at 20-21.

With respect to seasonal allocation of capacity, Power Advisory agreed with ORS Witness Horii's conclusion that avoided costs should be calculated based on current solar levels, rather than expected future solar levels, even where these are based on a legislated policy commitment. Power Advisory recommended that the Commission adopt the seasonal capacity weightings proposed in Witness Horii's Surrebuttal Testimony.[120] They agreed that the concerns raised by SACE/CCL Witness Wilson are "compelling that Duke's approach to modeling the impact of extreme temperatures is problematic," but noted that Mr. Wilson does not suggest specific changes to be made to the summer vs. winter capacity ratings without further analysis. Power Advisory also noted that the seasonal allocation figures proposed by SCSBA Witness Burgess "represent a reasonable check on the LOLE modeling" conducted by other parties.[121]

d. The Commission's Conclusions Regarding Avoided Capacity Costs

The Commission concludes that, although DEC and DEP were reasonable to use the peaker methodology to calculate avoided capacity costs, their application of the methodology was unreasonable for several reasons. Consequently, DEC's and DEP's proposed capacity rates are not fair, just, or reasonable.

Resource Plan. The utility's resource plan is a cornerstone of its avoided capacity calculations, as it constitutes the "base case" and informs the "change case" used under the peaker (or DRR) method. As noted above, DEC did not base its avoided cost calculations on an up-to-date resource plan. Subsequent to filing its IRP and the avoided cost calculations in this matter, DEC announced that it planned to accelerate the retirement of several of its coal-fired generation units. Specifically, the retirement of Allen units 4 and 5 (with a total capacity of 526 MW) will be

[120] *Id*. at 26-27.
[121] Power Advisory Report at 17.

moved up from December 2028 to 2024; and the retirement of the 540 MW Cliffside Unit 5 will be accelerated from 2032 to 2026. DEP also announced, in a rate request filed with the North Carolina Utilities Commission after the hearing, that it planned to accelerate the retirement of several coal units, including the Mayo Unit 1 and Roxboro Units 3 and 4, which are now scheduled to be retired in 2029.[122] Although these earlier retirements are not reflected in the IRP, Duke was aware of the plan to accelerate them as early as December 2018.[123] These early retirements may have a significant impact on avoided capacity costs in and it was unreasonable for the utility not to account for them in its avoided cost calculations.

The Commission acknowledges that the utility must, at some point, "snap the chalk" on avoided cost calculations and choose a set of inputs that reasonably approximates expected conditions. However, Duke was aware of the potential for accelerated retirement of these coal units as early as December 2018, and Mr. Snider (who has primary responsibility for the company's avoided cost calculations) was aware of the accelerated retirements when the company began its avoided cost calculations in the spring of 2019.[124] Although Mr. Snider testified that he thought the accelerated retirements might actually lower avoided energy costs, SCSBA Witness

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[122] See *Duke Energy Progress, LLC's Application to Adjust Retail Rates, Request for an Accounting Order and to Consolidate Dockets*, NCUC Docket No. E-2, Sub 1219 (Oct. 30, 2019) at 8-9 ("As explained by Witness John Spanos, the depreciation study includes additional accelerated retirement dates for coal units at Mayo 1 and Roxboro 3 and 4 to reflect the industry's shift towards retiring coal units earlier to manage the carbon footprint risk and to reflect changing economic conditions and environmental regulations… [T]he Company believes that reflecting the moderate reduction in the expected lives of these coal plants in depreciation rates gives the Company the flexibility to reduce its reliance on coal faster and invest in cleaner energy sources sooner, for the benefit of its customers."). The Commission takes judicial notice of these filings, which rely on the same December 2018 Depreciation Study that was relied on in the DEC rate application and was admitted as Hearing Exhibit No. 4.

[123] Hearing Vol. 1 at 151:22-153:19, 161:9-163:11; Hearing Ex. 3, 4.

[124] Hearing Vol. 1 at 163:6-10.

Burgess took the opposite view, and in any event it is not possible to ascertain the impacts on energy costs without conducting further analysis.

Under the circumstances, it was unreasonable for DEC and DEP to rely on the resource plans in their IRPs for purposes of their avoided cost calculations, despite knowing that these plans were inaccurate.

Consequently, the Commission concludes that: (1) DEC's avoided capacity costs should be adjusted to reflect a one-year acceleration of the year in which capacity is first required to 2025, to reflect the accelerated retirements; and (2) for purposes of calculating avoided capacity costs for Large QFs, Duke shall use an updated resource plan that incorporates the planned unit retirements for DEC and DEP. Furthermore, in future avoided cost proceedings, Duke shall endeavor to use the most up-to-date information concerning its resource plan in support of its avoided cost calculations. Duke must also include detailed information about the resource plan relied on in its initial filings, so that Intervenors have adequate opportunities to evaluate the assumptions in that plan.

Seasonal allocation. The Commission concludes that the Companies' approach to seasonal allocation of capacity is unreasonable, for several reasons.

First, as noted by ORS Witness Horii and others, it is speculative and unreasonable for Duke to base its capacity allocation on the "Tranche 4" level of solar penetration. Witness Horii compellingly described in his direct testimony how the assuming an unrealistic seasonal allocation based on a hypothetical amount of procurement could result in the utility being unable to procure that amount of capacity. At the hearing, Duke Witness Brown acknowledged that Duke did not meet its CPRE Tranche 1 goals.[125] It would be speculative to assume that the full amount of CPRE

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[125] Hearing Vol. 1 at 89:13-90:1.

solar will be procured, especially if avoided capacity costs are unreasonably low. More fundamentally, as noted by Power Advisory, "the avoided capacity cost of solar added to the system today should be based on the amount of solar on the system today," not some hypothetical future amount.[126] In the event Duke revises its seasonal allocation of capacity in the future, it shall consider only those solar resources actually under contract (and reasonably likely to enter service) rather than any hypothetical future procurement.

The Commission also finds persuasive the testimony of SACE/CCL Witness Wilson that the Companies' approach to modeling demand during extreme cold weather events is highly problematic, even if it is not clear precisely what the magnitude of the impacts would be. The Commission will require Duke, in the event it seeks to revise its seasonal allocation of capacity in later proceedings, to provide further empirical support for its assessment of demand during extreme cold weather events. This should include a sensitivity analysis where historical years prior to 1990 are removed, as those years may be unrepresentative of current weather patterns.

The Commission further concludes that SCSBA Witness Burgess's recommended seasonal allocation of capacity (as presented in his Surrebuttal testimony), which are reasonably close to ORS's recommended allocation, and constitute a reasonable approximation of both the Tranche 1 solar penetration levels and the impact of modeling errors identified by SACE/CCL Witness Wilson. Accordingly, the Commission approves the following seasonal allocation of capacity, which shall be applied both to the Standard Offer and to negotiated PPA rates:[127]

DEC		**DEP**	
Summer	Winter	Summer	Winter
58%	42%	4%	96%

[126] Power Advisory Report at 27.
[127] Hearing Vol. 2 at 787.22-787.23 (Burgess Surrebuttal Table 3).

Capital Cost Assumptions. The Commission finds persuasive ORS witness Horii's argument the that company must either assume a 20-year useful life for the avoided peaker unit used in its capacity calculations, or include fixed operation and maintenance ("FOM") costs as part of the total fixed costs of the peaker. The company cannot have it both ways. The Commission concludes that it was unreasonable of the company to assume a 35-year useful peaker life, and that it must instead use a 20-year useful life in its capacity calculations.

The Commission is also persuaded that the avoided cost of an incremental capacity unit may differ from the low-cost peaker unit, including economies of scale, that Duke has proposed. It is not sufficiently clear that the "high-efficiency" gas plants Duke intends to use to replace retiring capacity[128] would be an aeroderivative CT to require that such unit be included in the avoided cost calculation. However, the Commission does not find the general approach to be unreasonable of selecting the midpoint of two possible generation technology capital costs. The Commission agrees with Witness Burgess' testimony[129] that the replacement units are likely to reflect a combined cycle natural gas unit, which would have a higher capital cost than what Duke has proposed in its calculation. Accordingly, the Commission concludes that Duke should use the midpoint of an advanced CT and a combined cycle unit (similarly based on EIA inputs) for determining the avoided capacity cost for DEC. This reflects a reasonable balance between what SCSBA and Duke have proposed.

Near-term Capacity Purchases. The Commission agrees with Witness Snider's testimony that "an avoided cost rate need not include capacity unless the QF purchase will permit the purchasing utility to avoid building or buying future capacity."[130] However, to the extent that any

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[128] Hearing Vol. I at 164 (Snider Cross).
[129] Hearing Vol. I at 444 (Burgess Redirect).
[130] Power Advisory Report at 21.

near-term market capacity purchases can be avoided prior to 2025, these should be reflected in DEC's avoided cost calculation.

Commission Conclusion as to Avoided Capacity Rates. All the intervenors who provided testimony in this case – ORS, JDA, SBA, and SACE/CCL – identifying methodological flaws with Duke's avoided capacity calculations. Power Advisory also identified significant problems. Based on the evidence presented above the Commission concludes that Duke's proposed avoided capacity rates and calculation methodologies are not reasonable.

As with avoided energy rates, it is possible to clearly quantify the impacts of some, but not all, methodological problems based on the evidence in the record. The Commission concludes that the avoided capacity rates proposed by SCSBA Witness Burgess represent fair, accurate, and reasonable estimates of avoided energy costs for purposes of the Standard Offer, which are in the public interest and consistent with the language and intent of Act 62. The Commission will approve those rates for inclusion in the Standard Offer for DEC and DEP, and will (as discussed above) require Duke to adjust its avoided cost calculation methodologies for Large QFs and later Standard Offer rates to reflect these methodological changes.

C. Duke's Proposed Solar Integration Charge

1.Duke Testimony

In this proceeding DEC and DEP each proposed charges that they assert represent the costs they incur to integrate intermittent renewable energy generation onto their respective electric systems. Duke proposes a Solar Integration Charge ("SIC") that is based on the results of a 2018 study completed by Astrapé Consulting entitled Duke Energy Carolinas and Duke Energy Progress Solar Ancillary Service Study (the "Astrapé Study"). Duke Witness Wintermantel testified describing the Astrapé Study methodology, the findings of the Astrapé Study, Duke's proposed application of the SIC to solar facilities, the proposed cap, and the proposed biennial update to the integration charge. Based on the findings of the Astrapé Study DEC and DEP proposed a SIC of $1.10/MWh and $2.39/MWh, respectively, which would be updated biennially. DEC and DEP prosed a cap of $3.22/MWh and $6.70/MWh for solar facilities subjected to the SIC during this initial biennial period.

Duke Witness Snider described Duke's justification for the proposed SIC, Act 62's requirement that the Commission consider ancillary services in established avoided cost rates, the quantification and application of the proposed SIC, and the ability for solar facilities to mitigate the SIC through storage or other means. Duke Witness Wheeler also discussed Duke's justification for the proposed SIC, the proposed structure and rate design of the SIC, updating the SIC and the proposed cap, and the ability for solar facilities to avoid the SIC.

In response to the direct testimony of SCSBA, CCL and SACE, and ORS witnesses, Duke Witness Holeman testified regarding the operation of the Companies' power systems, relevant NERC reliability standards, and the integration of intermittent generation onto the Companies' systems.

2.SCSBA Testimony

SCSBA Witness Burgess critiqued Duke's proposed SIC. Mr. Burgess emphasized that Act 62 provides specific guidelines for the Commission to conduct an independent integration study, pursuant to S.C. Code Ann. § 58-37-60. Rather than relying on a study commissioned by Duke without stakeholder input or neutral third-party analysis, Mr. Burgess recommended that the Commission conduct the independent integration study contemplated by Act 62 before determining whether any integration charge is appropriate.

Mr. Burgess also addressed methodological flaws in the Astrapé Study used by Duke to calculate and justify the SIC. Mr. Burgess recommended that if the Commission were to adopt an integration charge in this proceeding before conducting the independent integration study, multiple alterations to the calculation of the SIC should be made to address the deficiencies in the Astrapé Study.

SCSBA Witness Levitas also described his serious concerns about Duke's proposed integration charge. Specifically, Mr. Levitas described Duke's proposed integration charge cap, which would allow Duke to increase the integration charge on an existing QF during the PPA up to the amount of the cap and would require the QF to assume that the integration charge applied at the level of the cap after the first two years of the contract.

3.CCL and SACE Testimony

CCL and SACE Witness Kirby explained that the Astrapé Study contained multiple serious methodological flaws, which led the Astrapé Study to calculate an unreasonable and excessive SIC that would impose costs on solar QFs that are not rationally related to any integration costs these QFs might actually impose upon the utilities' systems. Mr. Kirby also discussed how other jurisdictions have adapted to increased renewable penetration on the grid and explained that contrary to the Astrapé Study's findings, the cost of renewable integration does not increase, and has in fact decreased as renewable penetration increases. Moreover, Mr. Kirby testified Duke's historical operating reserve data illustrates that operating reserves have not been correlated with increased solar penetration—in other words, the Companies' assertion that increased solar capacity has increased operating reserves and therefore increased costs imposed upon customers, is not supported by historical data. For all these reasons, Witness Kirby recommended that Duke's proposed SIC be rejected.

4.ORS Testimony

ORS Witness Horii testified that in his experience integrating renewable generation can create additional costs for utilities by requiring additional ramping capability and reserves to meet the intermittent nature of solar and wind generation, which can include higher start-up costs, fuel costs, and O&M costs. Mr. Horii testified that he considered Duke's SIC analysis to be an acceptable approach to estimating solar integration charges, but he observed that the results of the Astrapé Study may indicate higher solar integration costs than would be required if the Companies sought to minimize those integration costs in the ways he recommended, and he disagreed with the Companies' proposal to use average integration costs that update annually. Mr. Horii testified that DEC's and DEP's proposed SIC of $1.10/MWh and $2.39/MWh should constitute an upper limit for the Companies' SIC, and that if future integration studies produce lower integration costs, the Companies' SIC for projects under this vintage of SIC rates should be updated to reflect those lower values.

5.Stipulation

On October 21, 2019, the Companies, SCSBA, JDA, and CCL and SACE entered into a Partial Settlement Agreement under the following terms:

1. DEC and DEP's quantification of the near-term projected capacity represented by "Existing plus Transition" solar QFs to be installed on the DEC and DEP systems, 840 MW and 2,950 MW, respectively, is reasonable for use in this proceeding.

2. That solar integration services charges (SISC) of $1.10/MWh (DEC) and $2.39/MWh (DEP) are reasonable, for purposes of this proceeding, for solar small power producers that enter into a PPA or establish a Legally Enforceable Obligation prior to the effective date of avoided cost calculations and methodologies filed in the next DEC / DEP avoided cost proceeding conducted by the SC Public Service Commission. These charges shall not be subject to adjustment during the term of the PPA. The SISC in the foregoing amounts should apply prospectively only to projects subject to the avoided cost methodologies and contractual terms and conditions established in this

proceeding, and shall not apply to the rates established in prior avoided cost proceedings; nor shall it be binding with respect to any subsequent avoided cost proceeding.

3. Duke cannot impose the SISC on a solar QF that is a "controlled solar generator," meaning, generally, any solar QF that demonstrates that its facility is capable of operating, and contractually agrees to operate, in a manner that materially reduces or eliminates the need for additional ancillary service requirements incurred by the utility, including but not limited to QFs equipped with battery storage. Duke must to file with the Commission by November 18, 2019, for review and comment, proposed guidelines for QFs to become "controlled solar generators" and thereby avoid the SISC.

4. The Astrapé Study used to calculate the SISC presents novel and complex issues that warrant further consideration. Duke shall submit the study methodology and inputs to an independent technical review and include the results of that review and any revisions in its initial filing in the next avoided cost proceeding. To the maximum extent practicable the independent review of the study methodology shall take into consideration the South Carolina Integration Study called for by S.C. Code Ann. § 58-37-60. This process shall be subject to Commission oversight and comment from interested stakeholders. The parties agree that undertaking the work associated with the independent technical review is reasonable and appropriate to effectuate Act 62 compliance.

5. Within 15 days of the Commission's final Order approving the SISC, unless otherwise directed by the Commission, and as agreed to in this Stipulation, Duke shall file revised Standard Offer and Large QF purchase power agreements and terms and conditions, in redline and clean versions, that comply with the contract terms and conditions specified in this Stipulation.

6. To the extent the Companies propose to impose the SISC for any other programs or contexts in South Carolina, the Commission will separately consider the appropriateness and applicability of the SISC in the proceedings to consider and review those programs.

The parties to the Partial Settlement Agreement assert that the settlement is just, fair, reasonable, in the public interest, and in accordance with law and regulatory policy. During the evidentiary hearing, ORS represented to the Commission that it did not object the terms of the Partial Settlement Agreement.[131]

6.The Commission's Conclusions Regarding the Proposed SISC

[131] Hearing Vol. 1 at 179.

S.C. Code Ann. § 58-41-20(B)(3) requires the Commission to ensure that each electrical utility's avoided cost methodology fairly accounts for costs avoided by the electrical utility or incurred by the electrical utility, including but not limited to, energy, capacity, and ancillary serves provided by or consume by small power producers including those utilizing energy storage equipment. S.C. Code Ann. § 58-37-60 permits the Commission and ORS to initiate an independent study to evaluate the integration of renewable energy and emerging energy technologies into the electric grid for the public interest.

These proceedings represent the first instance in which the Commission has been asked to consider the adoption an "integration charge" of this type that would apply to solar energy generators. As demonstrated by the testimony of the Parties to this proceeding, these are complicated issues that require further study and analysis, as specifically contemplated by S.C. Code Ann. § 58-37-60. However, the Commission considers the October 21, 2019 Partial Settlement Agreement to be a reasonable outcome in this proceeding to address this novel issue pending further study, and the Commission therefore accepts the Partial Settlement Agreement in its entirety.

The Commission also notifies the Parties that within ninety (90) days of the date of this Order, the Commission shall open a docket pursuant to S.C. Code Ann. § 58-37-60 in which to initiate an independent study to evaluate the integration of renewable energy and emerging energy technologies into the electric grid for the public interest. The Commission will provide further information at that time regarding the proposed scope of the study and a Request for Proposal to select an independent party to conduct the study.

D. <u>Proposed PPA Terms and Conditions</u>

1.Duke Testimony

Duke asks this Commission to approve its proposed Standard Offer (as that term is defined by S.C. Code Ann. § 58-41-10(15)), which includes the Companies' respective Schedule PP (SC) Purchased Power tariffs ("Standard Offer Tariff" or "Schedule PP"), Terms and Conditions for the Purchase of Electric Power ("Standard Offer Terms and Conditions" or "Terms and Conditions"), and Standard Offer power purchase agreement ("Standard Offer PPA") available to all qualifying cogenerators and small power production facilities up to 2 MW in size. Duke also seeks approval of a form of power purchase agreement available to small power producer QFs between 2 and 80 MW that are not eligible for the Standard Offer ("Large QF PPA") (collectively with the Standard Offer Tariff, Standard Offer Terms and Conditions, and Standard Offer PPA, "the Proposed Contracts").[132]

In response to testimony of SCSBA, JDA, and ORS, Duke has agreed to make multiple changes to its Standard Offer PPA and its Large QF PPA. The changes Duke has agreed to for the Standard Offer PPA are as follows:

a. Agreeing that Duke will not unreasonably withhold, condition, or delay consent to a QF's request to make a "Material Alteration";

b. Agreeing to remove "estimated annual energy production" from Duke's definition of Existing Capacity;

c. Agreeing to adopt a modification to Duke's Storage Protocol whereby the QF is required to levelize the output of the overall Facility (solar plus storage) over the Capacity Hours, thereby avoiding the need for curtailment.

The changes Duke has agreed to for the Large QF PPA are as follows:

a. Agreeing to adopt a modification to Duke's Storage Protocol whereby the QF is required to levelize the output of the overall Facility (solar plus storage) over the Capacity Hours, thereby avoiding the need for curtailment;

[132] Joint Application at 2.

b. Agreeing to replacing PPA termination for failure to comply with confidentiality or publicity provisions of the PPA with liquidated damages but maintaining all legal remedies available as need be;

c. Agreeing to entering into a new or modified PPA agreement that is consistent with the Commission's Order;

d. Agreeing to include force majeure as a reason to extend the COD Milestone Date;

e. Agreeing to set the COD Milestone Date at 90 days after the Interconnection Facilities and System Upgrades In-Service Date and allow for day-to-day extensions to account for any delays not caused by the Seller QF.

With respect to the other issues addressed by intervenors, Duke has declined to make changes to its proposed terms and conditions. For the Standard Offer PPA, these remaining issues include (1) whether material alterations to the Standard Offer PPA should apply retroactively or only prospectively; and (2) Duke's proposed 30-month in-service date following avoided cost rate approval. Duke Witness Wheeler testifies that changes to the Standard Offer PPA approved by this Commission should apply not only to future contracts but should also apply prospectively to existing contracts.[133] Duke Witness Wheeler also testifies that the 30-month in-service requirement is necessary to prevent QFs from receiving "stale" rates.

With respect to the Large QF PPA, these remaining issues include: (1) Duke's proposal to require a Facilities Study Agreement ("FSA") as a condition of signing a Large QF PPA; (2) the interconnection facilities and network upgrade cost threshold that allows a QF an offramp to the PPA; and (3) whether Surety Bonds should be considered a permissible form of performance security. Duke Witness Johnson testifies that requiring the QF to have retuned an FSA will require the QF to demonstrate the commercial viability of the project.[134] With respect to an offramp for interconnection costs over a certain threshold, Witness Johnson testifies that allowing a QF to

[133] Hearing Vol 1 at 262.
[134] Hearing Vol. 1 at 284.11 (Johnson Rebuttal).

terminate the PPA if interconnection costs exceed a predetermined threshold would allow the QF terminate the PPA without penalty.[135] Witness Johnson also testifies that Duke has never allowed surety bonds to be a permitted form of performance assurance and that the Companies continue to take this position.[136]

2.SBA Direct Testimony

SCSBA Witness Levitas raised many concerns with Duke's proposed Standard Offer PPA and Large QF PPA in his direct testimony. As discussed above, in his rebuttal testimony and during the evidentiary hearing, Mr. Levitas discussed the resolution of a number of these contested issues. With respect to the Standard Offer PPA, in addition to the issues agreed to by Duke and those still in controversy discussed above, Witness Levitas accepted Duke's proposed "Material Alteration" definition subject to two modifications: first, the Terms and Conditions need to provide that Duke's consent to requested material alterations will not be unreasonably withheld, conditioned or delayed. Witness Levitas stated that Duke has agreed to a similar condition in its Large QF PPAs. Second, the proposed terms and conditions must be applied only prospectively to new PPAs and not be made applicable to existing PPAs.[137] Duke has agreed to the first condition but has not agreed to the second condition.

With respect to the Large QF PPA, in addition to the issues agreed to by Duke and those still in controversy discussed above, Witness Levitas agreed to accept Duke's proposal that QFs failing to timely meet the commercial operation date ("COD") in the PPA would be subject to liquidated damages equal to the lesser of (1) 2% of total expected revenue over the life of the

[135] Hearing Vol 1 at 268.
[136] Hearing Vol 1 at 278.
[137] Hearing Vol 1 at 324.12 (Chilton Direct).

project, or (2) the average annual estimated capacity payments under the Agreement over the Term for up to 15 MW and $10,000/MW-AC thereafter for projects larger than 15 MW.[138]

3.JDA Testimony

JDA Witness Chilton testified that the expansion of QFs in South Carolina as envisioned by PURPA and further prioritized by Act 62 rests on the ability of QFs to attract regularly available, market-rate financing from reputable providers, which in turn relies on fair and commercially reasonable PPA contract terms.[139]

4.ORS Testimony

ORS Witness Horii testified that, based on his experience, Duke's proposed Standard Offer PPA and Large QF PPA terms and conditions are non-discriminatory, commercially reasonable, and conform with applicable legal standards.[140] During the evidentiary hearing, Witness Horii acknowledged that he did not personally have experience negotiating QF contracts of the type at issue in this proceeding and that he had relied upon other members of his team at E3 in assessing the reasonableness of the PPA terms and conditions.[141] Mr. Horii also acknowledged that those E3 employees were not available for cross-examination at the hearing and that, although he had reviewed the contracts quite a while ago, he had not scrutinized every aspect of the PPAs.[142]

5.Power Advisory's Conclusions

Power Advisory reviewed the Standard Offer PPA and the Large QF PPA, as well as the testimony and evidence presented by Parties in this proceeding. In its November 1, 2019 report, Power Advisory noted the issues that been resolved between Duke and SCSBA, and it addressed

138 *Id*. at 324.3.
139 Hearing Vol. 1 at 324.9 (Chilton Direct).
140 Hearing Vol. 2 at 525.26 (Horii Direct).
141 Hearing Vol. 2 at 540-542
142 *Id*. at 542.

the issues that remained in controversy. With respect to the remaining issues in controversy, the Power Advisory report agreed with SCSBA Witness Levitas on the following contested issues relating to the Standard Offer PPA:

a. Material alterations to the Standard Offer PPA should apply only prospectively, not retrospectively;[143] and

b. Duke's proposed 30-month in-service date following avoided cost rate approval should be extended day-for-day for any delays attributable to the in-service date of these interconnection facilities, which Duke has already agreed to for the Large QF PPA.[144]

With respect to the remaining issues in controversy relating to the Large QF PPA, the Power Advisory report agreed with SCSBA Witness Levitas on the following contested issues:

1. Duke's proposal to require a Facilities Study Agreement ("FSA") as a condition of signing a Large QF PPA should only apply if the QF has received a System Impact Statement from the utility within one year of the Interconnection Request. This will prevent Duke from controlling or frustrating QF development through unreasonable delays in interconnection;[145]

2. Duke should either: (1) provide the System Impact Study within 1 year of interconnection request (or an amount of time that is mutually agreeable between the buyer and seller) or (2) allow an offramp to the QF. The Power Advisory report noted that Dominion has accepted the offramp provision.[146]

The Power Advisory report also concluded that Duke should not be required to offer a surety bond as a form of performance assurance, noting that Duke already allows three options for performance assurance and that Duke has previously determined that surety bonds posed more risks than other options.[147]

6.The Commission's Conclusions Regarding Proposed PPA Terms and Conditions

143 Power Advisory Report at 44.
144 *Id*. at 45.
145 *Id*. at 47-48.
146 *Id*. 49.
147 *Id*. at 51.

PURPA provides states significant discretion in the establishment of QF contract terms and conditions. Act 62 provides this Commission specific guidance as to the requirements of power purchase agreements approved under the Act, including requiring this Commission to approve power purchase agreements, including terms and conditions, that are commercially reasonable and consistent with regulations and order promulgated by FERC implementing PURPA. S.C. Code Ann. § 58-41-20(B)(2).

As described above, the PPA and terms and conditions issues in dispute were primarily addressed by Duke and SCSBA. Although ORS Witness Horii concluded that Duke's proposed PPAs were generally reasonable, the Commission gives little weight to Witness Horii's findings on these issues based on Mr. Horii's acknowledgement that he has little or no experience negotiating or analyzing contracts of this type and that he did not closely scrutinize the PPAs prior to reaching his conclusion.

With respect to the issues no longer in controversy between the Companies and SCSBA, the Commission accepts as reasonable the consensus reached on the following issues relating to the Standard Offer PPA:

1. Adopting Duke's definition of "Material Alteration" including the condition that Duke will not unreasonably withhold, condition, or delay consent to a QF's request to make a "Material Alteration";

2. Removing "estimated annual energy production" from Duke's definition of Existing Capacity;

3. Adopting a modification to Duke's Storage Protocol whereby the QF is required to levelize the output of the overall Facility (solar plus storage) over the Capacity Hours, thereby avoiding the need for curtailment.

With respect to the remaining Standard Offer PPA issues in controversy, the Commission agrees with the testimony and recommendations of SCSBA Witness Levitas and Power Advisory regarding the application of changes to the Standard Offer PPA. The Commission recognizes that

Duke's Standard Offer PPA currently includes language that applies changes to the terms and conditions of those contracts retroactively on existing contracts, other than those relating to rates or essential terms and conditions. The Commission agrees that changing contract terms and conditions retroactively can have a chilling effect on existing and future financing and that it does not represent sound public policy. This is particularly true given the take-it-or-leave-it nature of Standard Offer PPAs, which provide QFs no ability to negotiate, and the fact that QFs lack other viable buyers for their output in South Carolina. Allowing changes to apply retroactively would be commercially unreasonable.

Next, with respect to Duke's proposed 30-month in-service date following avoided cost rate approval, the Commission agrees with SCSBA and Power Advisory that the 30-month in-service date should be extended day-for-day to account for any delays attributable to the in-service date of these interconnection facilities. The Commission notes that Duke has agreed to this provision for the Large QF PPA, and it would be appropriate to include the same provision in the Standard Offer PPA. The Commission agrees with SCSBA Witness Levitas that delays in the interconnection process that are outside of the control of the QF should toll the 30-month in-service date.

Turning to the Large QF PPA, the Commission accepts as reasonable the consensus reached by Duke and SCSBA on the following issues:

1. Adopting a modification to Duke's Storage Protocol whereby the QF is required to levelize the output of the overall Facility (solar plus storage) over the Capacity Hours, thereby avoiding the need for curtailment;

2. Replacing PPA termination for failure to comply with confidentiality or publicity provisions of the PPA with liquidated damages but maintaining all other legal remedies available;

3. Entering into a new or modified PPA agreement that is consistent with the Commission's Order;

4. Including force majeure events as a reason to extend the COD Milestone Date;
5. Setting the COD Milestone Date at 90 days after the Interconnection Facilities and System Upgrades In-Service Date and allow for day-to-day extensions to account for any delays not caused by the Seller QF.

With respect to the remaining Large QF PPA issues in controversy, the Commission agrees with the testimony and recommendations of SCSBA Witness Levitas and Power Advisory regarding Duke's proposal to require a Facilities Study Agreement ("FSA") as a condition of signing a Large QF PPA. The Commission agrees that the QF faces the possibility that delays in the interconnection process may delay the receipt of a System Impact Study, which will in turn prevent the QF from delivering an FSA to the utility. Such interconnection delays should not unduly prevent the QF from entering into a PPA. Therefore, Duke's proposal to require an FSA as a condition of signing a Large QF PPA should only apply if the QF has received a System Impact Study from the utility within one year of the Interconnection Request. If the SIS has not been received within one year, the requirement for the QF to deliver the FSA should be lifted. This will prevent Duke from controlling or frustrating QF development through unreasonable delays in interconnection.

With respect to a provision allowing the QF to terminate the PPA without penalty if interconnection facilities and network upgrades exceed a certain threshold, the Commission agrees with the testimony and recommendations of SCSBA Witness Levitas and Power Advisory. The Commission agrees with Witness Levitas that the need for an offramp would be obviated if the QF received a SIS within one year of submitting its Interconnection Request, which would provide the QF the information it needed to determine whether or not to execute a PPA. In the event that a QF does not receive an SIS within one year, the Commission agrees with Witness Levitas and Power Advisory that it would be reasonable to allow the QF to terminate its PPA if the interconnection costs exceed $75,000/MW-AC, and the Commission notes that Dominion has also agreed to this provision.

Finally, the Commission agrees with Witness Levitas that the Companies should be required to offer a surety bond as a form of performance assurance, in addition to cash, a letter of credit, and a guarantee. Although Duke has testified that they previously considered offering surety bonds and determined that they posed more risks than other options, the Commission considers surety bonds to be a commercially reasonable form of performance assurance, and on balance, the benefit of the availability of a surety bond for QFs outweighs any risk to the Companies of offering a surety bond, which the Commission considers to be minimal. The Commission notes that Dominion has agreed to allow the use of surety bonds for PPA performance assurance and has proposed a surety bond form that Mr. Levitas agreed is commercially reasonable. The Commission directs Duke to make the same surety bond form available under its Large QF PPAs.

E. Proposed NoC Form and LEO Standard

Act 62 provides that "[a] small power producer shall have the right to sell the output of its facility to the electrical utility at the avoided cost rates and pursuant to the power purchase agreement then in effect by delivering an executed notice of commitment to sell form to the electrical utility." S.C. Code Ann. § 58-41-20(D). Under PURPA, a QF is able to "lock in" fixed avoided cost rates at the time it establishes a LEO. Act 62 requires the Commission to approve, in this docket, a standard notice of commitment ("NoC") Form that a QF may deliver in order to establish a LEO. Act 62 requires a NoC Form "that provides the small power producer a reasonable period of time from its submittal of the form to execute a power purchase agreement." It further provides that "in no event… shall the small power producer, as a condition of preserving the pricing and terms and conditions established by its submittal of an executed commitment to sell form to the electrical utility, be required to execute a power purchase agreement prior to receipt of a final interconnection agreement from the electrical utility." *Id.*

1.Duke Testimony

Duke requests that the Commission approve a NoC Form that incorporates Duke's proposed standard for establishing a LEO.[148] In Direct testimony Duke proposed a NoC Form that would require a QF to meet the following prerequisites in order to establish a LEO:

1. Required Certification with FERC as QF;
2. Required Commitment to Execute PPA within 90 days and to deliver power within 365 days of Notice of Commitment Form Submittal Date;
3. Demonstration of Control of Project Site and Required Permits; and
4. Requirement to Be Interconnection Customer of Utility.

In response to criticism from SBA Witness Levitas, Duke agreed to revise its NoC Form to provide a 10 Business Day cure period for missing the COD date, ceasing to have site control, or ceasing to be certified as a QF with FERC, and to remove the requirement that Seller will make the Company whole for any damages or expenses arising from Seller's breach of any warranty, representation, or covenant in this Notice of Commitment.[149]

2.SCSBA Testimony

SCSBA Witness Levitas provided testimony concerning FERC's guidance to states concerning LEO standards. Mr. Levitas testifies that in order to form a LEO a QF must make a binding commitment to sell its output to the utility, subject to consequences for failing to do so. Mr. Levitas argues that Duke's proposed NOC includes unreasonable requirements, including requiring the QF to have secured all required permits and requiring the QF to deliver power within

[148] Joint Application at 2.
[149] Johnson Rebuttal Exhibit 1 – Redline, pp. 8-9.

365 days of submitting the NoC Form.[150] Mr. Levitas testified that SCSBA would withdraw its objection to the 365-day requirement if that time was extended to account for additional time required for interconnection facilities and network upgrades.[151] Witness Levitas also discusses ways to address Duke's claims regarding "stale" avoided cost rates.[152] Witness Levitas included a proposed alternative NOC form as an Exhibit to his prefiled testimony.[153]

3.Power Advisory Conclusions

Power Advisory reviewed the Proposed NoC Form, as well as the testimony and evidence presented by Parties in this proceeding. In its November 1, 2019 report, Power Advisory addressed the remaining issues in controversy. With respect to Duke's proposal that a QF must obtain all required permits and land-use approvals prior to LEO formation, Power Advisory addressed the arguments made by Duke and by SCSBA and concluded that since SCSBA has agreed to the 365 day in-service date requirement (conditional on obtaining a System Impact Study), that QFs be allowed to secure permits after formation of a LEO, so as to balance the two issues.[154] Power Advisory noted that this was consistent with the Large QF PPAs which do not require permits to be obtained before execution.[155]

With respect to Duke's proposal that a QF must be placed in-service within 365 days of executing the NoC Form, Power Advisory addressed the arguments made by Duke and by SCSBA and concluded that a 365 day in-service date is appropriate so long as the COD date is extended to 90 days following the completion of the utility upgrade work. Power Advisory

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[150] Hearing Vol. 1 at 322.25 (Levitas Direct).
[151] *Id*. at 324.8.
[152] *Id*. at 322.27.
[153] Hearing Exhibit 11 (Levitas-4).
[154] Power Advisory Report at 52-53.
[155] *Id*.

reasoned that this was an appropriate balance of interests and that the utility must bear some of the responsibility to ensure that the interconnection timeline is reasonable.[156]

4.The Commission's Conclusions Regarding the Proposed NoC Form and LEO Standard

FERC's regulations implementing PURPA establish the requirement that a QF have the option to choose to enter into a long-term fixed contracts with avoided costs set at the time the LEO is established.[157] FERC has stated that the "[u]se of the term 'legally enforceable obligation' is intended to prevent a utility from circumventing the requirement that provides capacity credit for an eligible qualifying facility merely by refusing to enter into a contract with the qualifying facility."[158] Similarly, and consistent with PURPA, Act 62 requires this Commission to approve a standard NoC Form to be used establish a LEO and provides that "in no event…shall the small power producer, as a condition of preserving the pricing and terms and conditions established by its submitted of an executed commitment to sell form to the electrical utility, be required to execute a power purchase agreement prior to receipt of a final interconnection agreement from the electrical utility." S.C. Code Ann. § 58-41-20(D).

After reviewing the testimony and evidence presented by Parties to this proceeding, the Commission first concludes that the proposed changes included in Duke Witness Johnson's rebuttal testimony revised NoC Form are reasonable and should be adopted.

[156] *Id.* at 55.
[157] 18 C.F.R. § 292.304(d)(2).
[158] *FLS Energy Inc.*, 157 FERC ¶ 61, 211 (2016)(citing *Final Rule Regarding the Implementation of Section 210 of the Public Utility Regulatory Policies Act of 1978*, Order No. 69, FERC Stats. & Regs. ¶ 30,128 at 30,880 *order on reh'g*, Order No. 69-A, FERC Stats. & Regs. ¶ 30,160 (1980), *aff'd in part & vacated in part sub nom. Am. Elec. Power Serv. Corp. v. FERC*, 675 F.2d 1226 (D.C. Cir. 1982), *rev'd in part sub nom. Am. Paper Inst. v. Am. Elec. Power Serv. Corp.*, 461 U.S. 402 (1983).

Next, with respect to Duke's proposed requirement that a QF must secure all required permits and land-use approvals prior to establishing a LEO, the Commission agrees with SCSBA Witness Levitas and Power Advisory that this requirement is unnecessarily burdensome for QFs and that it is unreasonable to expect a QF to incur the expense to secure permits and land-use approvals until it has secured a price for its output.

The Commission also agrees with SCSBA Witness Levitas and Power Advisory that in order to be eligible to form a LEO utilizing the NoC Form a QF must represent that it is capable of being placed in service within 365 days of submittal of the form or 90 days after Duke's completion of the required interconnection facilities and network upgrades.

Finally, SCSBA Witness Levitas also proposes that QFs that have submitted a NoC Form have the option to terminate the PPA if the cost of interconnection facilities and/or network upgrades exceed $75,000/MW-AC. The Commission adopts the same conclusions regarding this issue that it described above in the context of the Large QF PPA.

F. Proposals for PPAs with a Duration Longer than Ten Years

Act 62 expressly permits the Commission to "approve commercially reasonable fixed price power purchase agreements with a duration longer than ten years" as proposed by the intervenors.[159] PPAs in excess of ten years "must contain additional terms, conditions, and/or rate structures as proposed by intervening parties and approved by the commission, including, but not limited to, a reduction in the contract price relative to the ten year avoided cost."[160] Act 62 expressly directs the Commission "to consider the potential benefits of terms with a longer

[159] S.C. Code Ann. § 58-41-20(F)(1).
[160] *Id.*

duration to promote the state's policy of encouraging renewable energy" when approving intervenors proposals for PPAs with a tenor in excess of ten years.[161]

1.Duke Testimony

In this proceeding DEC and DEP asserted that contract lengths longer than ten years, where set by the Commission rather than through a competitive procurement process, could lead to stale rates. Duke Witness Brown testified that the current QF Contracts in North Carolina could lead to an "overpayment" of $2.26 billion dollars over the next 15 years. Duke Witness Snider reiterated that claim in support of the Companies' position that the Commission not approve PPAs with tenors in excess of ten years. Duke Witness Brown did agree that the Companies' "overpayment projection" was premature and that any "overpayment" or savings passed along to the customer under existing PPAs "will be determined over the next ten years."[162] Duke Witness Brown also acknowledged that the intervenors were proposing terms in excess of ten years in this proceeding.[163]

Duke Witness Holeman also testified that traditional non-dispatchable PURPA PPAs result in operational challenges for the utility, and he testified that the limited dispatch rights offered in CPRE contracts provide "significant benefits" to system operations, which, from his perspective as a system operator, constitute "a key benefit of [the CPRE program's] design."[164] Witness Holeman offered extensive testimony at the hearing about the operational benefits of the flexibility offered by CPRE-style dispatchable solar PPAs.[165]

2.SCSBA Testimony

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[161] S.C. Code Ann. § 58-41-20(F)(2).
[162] Hearing Vol. at 178.
[163] Hearing Vol. 2 at 689-690
[164] Hearing Vol. 2 at 758.40 (Holeman Rebuttal).
[165] Hearing Vol. 2 at 772:15-773:18, 775:20-776:6.

SCSBA Witness Davis addressed the Duke Witnesses' arguments against contracts in excess of ten years by characterizing the "overpayment argument" made by the Companies as "extremely distorted" and one that was dismissed by both the "ORS expert witness in this proceeding, and (by) our General Assembly."[166] SCSBA Witness Davis also pointed out that Duke admitted via press release[167] that its own customers are protected by the "20 years of cost-effective energy" as a result of the 20-year PPAs the Companies offer in North Carolina.[168] Most impactfully, SCSBA Witness Davis testified that "Duke's CPRE contracts are for 20 years at an average fixed rate of around $38 per megawatt-hour for Tranche 1," while Duke's proposal in this proceeding "would result in a ten-year contract in South Carolina for closer to $30 per megawatt-hour."[169] SCSBA Witness Davis, on behalf of the intervenors, goes on to offer testimony that supports "dispatchable PPAs" of 20 years in South Carolina just as are offered in North Carolina.[170]

3.JDA Testimony

JDA Witness Chilton provided expert testimony on the commercial reasonableness of certain terms of PPAs between the utility and qualifying small power production facilities as defined in PURPA and Act 62 and what tenor of contract is needed in South Carolina to effectuate Act 62. Ms. Chilton also addressed contentions made in Duke Witnesses' testimony as to the relative weight that PURPA and Act 62 give to their respective legislative goals to encourage renewable energy and how the balancing of those goals might affect terms provided by the utility in PPAs for small power producer QFs.[171]

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166 Hearing Vol. 2. at 812-813.
167 https://news.duke-energy.com/releases/competitive-process-yields-carolinas-biggest-one-day-collection-of-solar-projects-ever-significant-savings-for-duke-energy-customers
168 Hearing Vol. 2 at 802.12 (Davis Surrebuttal).
169 Hearing Vol. 2 at 795-796.
170 *Id*. at 796
171 Hearing Vol. 1 at 336.3-4 (Chilton Surrebuttal).

Ms. Chilton testified that both PURPA and Act 62 prioritize protection of ratepayers with "just and reasonable" rates while simultaneously requiring that state-level regulatory bodies refrain from mandating or approving terms and conditions of PPAs that discriminate against QFs.[172] Specifically, Ms. Chilton states that Act 62 requires this Commission to promote consumer interests along with the advancement of QFs, the diversification of the utility's generation mix, and the promotion of renewable energy in the state.[173]

Ms. Chilton put forth testimony that Act 62 expressly directs the Commission to approve PPAs which allow QFs to compete on even terms with the utility's other generation resources, both present and projected, and enable the QF to obtain regularly-available, market-rate financing for the costs of developing, building, and operating their projects. Ms. Chilton opines as to the definition of "regularly-available", market-rate financing and, from a lending perspective, what terms are necessary in PPAs to achieve this for QFs.

Witness Chilton addressed ratepayer protections that are associated with longer term contracts by offering testimony during the hearing that "if avoided costs go up and… [ratepayers] have a long-term avoided cost at a currently low rate, then… the longer the benefit [to the ratepayer]."[174] Ms. Chilton also offered her opinion that the threshold established in Act 62 is not whether it is possible for a QF to obtain financing under certain special circumstances; rather it is that PPA terms be commercially reasonable and allow QFs to attract regularly-available, market-rate financing. Ms. Chilton also offers a critique of Duke's proposed avoided costs. Finally, Ms. Chilton testified that a longer PPA contract term, accompanied by an appropriately calculated avoided cost purchase price, will lead to more mainstream capital availability for QF

[172] *Id*. at 336.5-6.
[173] *Id*.
[174] Hearing Vol. 1 at 346-347.

development.[175] Ms. Chilton testifies that Act 62 recommends a ten-year term as a "starting point" and expressly encourages this Commission to support contracts with terms longer than ten years as a means of promoting renewable energy.[176] Ms. Chilton recommended that the Commission set the tenor of PPA contracts at a minimum of 15 years with appropriate conditions as set forth in SC Code Ann. § 58-41-20(F)(1) to facilitate the opportunity to obtain financing for QFs in South Carolina.[177] To best comply with Act 62's goal of promoting renewable energy development in the state, Ms. Chilton recommended that this Commission direct that Duke's PPAs be offered at 15 to 20 years, and that some PPAs be approved for 20 years or longer, all with the appropriate statutory conditions as proposed by the intervenors pursuant to the Act.[178]

4.ORS Testimony

The ORS is statutorily charged with representing the public interest in all commission proceedings.**[179]** ORS sponsored testimony by Witness Horii that discussed ratepayer risk and benefits from PPA contracts longer than ten years. Mr. Horii disagreed with the Companies' unsupported overpayment risk to the ratepayers. Mr. Horii stated in filed testimony and that "there is no overpayment risk" to the ratepayers when avoided costs are accurately calculated and based on current conditions.**[180]** On the stand, Mr. Horii confirmed that it was his understanding that the ORS' role in these proceedings is "to represent the interests of the ratepayer".**[181]** After being reminded of that role, he expressly confirmed his written testimony that "if the avoided costs are calculated correctly there is no overpayment risk [to the ratepayer]" from longer term PPA

[175] Hearing Vol. 1 at 324.8-9 (Chilton Direct).
[176] *Id*. at 324.9.
[177] *Id*. at 324.10.
[178] *Id*. at 324.10-11.
[179] S.C. Ann. § 58-4-50(4).
[180] Hearing Vol. 2 at 528.8-9 (Horii Surrebuttal).
[181] Hearing Vol. 2 at 543.

contracts.[182] The ORS witness Horii went on to further contradict Duke Witness Snider's concern about contracts longer than ten years harming ratepayers by pointing out that natural gas prices are at historic lows and that, as a significant driver of avoided costs, expects avoided cost rates to rise over the next 20 years if and when natural gas prices increase as projected.[183] Thus, ORS Witness Horii concludes that long-term PPAs fixed at current avoided costs would be not only protect the ratepayer but "actually ends up being a very strong… positive thing for ratepayers to have those contracts."[184]

5.The Commission's Conclusions Regarding Proposals for PPAs with a Duration Longer than Ten Years

This Commission approves Intervenors JDA's and SCSBA's proposals for PPAs longer than ten years, including terms up to 20 years. These proposals are consistent with the intent of the legislature in passing Act 62 and in compliance with South Carolina's express policy of encouraging renewable energy, as described below. Act 62 contains the following directive:

> Electrical utilities, subject to approval of the commission, shall offer to enter into fixed price power purchase agreements with small power producers for the purchase of energy and capacity at avoided cost, with commercially reasonable terms and a duration of ten years. **The commission may also approve commercially reasonable fixed price power purchase agreements with a duration longer than ten years, which must contain additional terms, conditions, and/or rate structures as proposed by intervening parties and approved by the commission, including, but not limited to, a reduction in the contract price relative to the ten year avoided cost.** Notwithstanding any other language to the contrary, the commission will make such a determination in proceedings conducted pursuant to subsection (A). The avoided cost rates applicable to fixed price power purchase agreements entered into pursuant to this item shall be based on the avoided cost rates and methodologies as determined by the commission pursuant to this section. The terms of this subsection apply only to those small power producers whose qualifying small power production facilities have active interconnection requests on file with the electrical utility prior to the effective date of this act. The commission may determine any other necessary terms

[182] *Id*.
[183] *Id*. at 548.
[184] *Id*. at 545.

> and conditions deemed to be in the best interest of the ratepayers. This item is not intended, and shall not be construed, to abrogate small power producers' rights under PURPA that existed prior to the effective date of the act.

S.C. Code Ann. § 58-41-20(F)(1).

The legislature has clearly indicated through Act 62 that the ten-year contracts that utilities must offer to QFs under Act 62 adequately protect ratepayers. Act 62 also expressly permits the Commission to approve contracts longer than ten years. The Commission finds that it is appropriate to approve contracts longer than ten years and that such longer-term contracts do not impose undue risk on ratepayers. The Commission is not persuaded by testimony from the Companies that contracts longer than ten years pose substantial risk to ratepayers. Rather, longer-term contracts pursuant to the requirements of Act 62 would appropriately balance the interests of ratepayer risk and the encouragement of independent small power producers in South Carolina.

Offering contracts longer than ten years is consistent with PURPA and FERC's implementing regulations and orders. PURPA has been interpreted by FERC as requiring that PPAs be of sufficient length to give the QFs "reasonable opportunities to attract capital." *Windham Solar LLC & Allco Fin. Ltd.*, 157 FERC ¶ 61,134 at ¶ 8 (2016). Neither PURPA nor FERC expressly state how long a contract must be in order to provide QFs a reasonable opportunity to attract capital, and the Commission finds the testimony provided by JDA Witness Chilton instructive in reaching a decision on this issue. JDA Witness Chilton testifies that "[r]easonable opportunities to attract capital" means that a QF must be able to obtain regularly-available, market-rate financing for the costs of developing, building, and operating their projects. This requires the Commission to consider types, terms, and providers of financing for QFs that are wholly different from the preferential financing that the utility enjoys by virtue of its monopoly status, history, and ability to rate-base the entirety of the cost of its generation facilities.[185] Witness Chilton testifies that in her expert opinion PPAs with tenors of at least 15 years and up to 20 years would facilitate the opportunity to obtain financing for a majority of QFs in South Carolina.[186] Power Advisory further points out, in comparing the 30 year contracts in Georgia and 20 year contracts in North Carolina, that fixed price PPAs for ten years in excess of $40 per MWh are necessary as the minimum price to "secure financing" in this proceeding under PURPA.[187] The Commission finds the testimony of Witness Chilton persuasive and agrees with the conclusions of Power Advisory.

PURPA also requires that ratepayers be protected under PURPA contracts. As discussed above, ORS witnesses, SCSBA Witnesses, and JDA Witness Chilton all opined that ratepayers will actually benefit from PPAs longer than ten years. By locking in low rates now, while gas is at a historic low, ratepayers will not only be protected but will very likely see a net savings over the life of the contract. Further, QF projects pose no risks of cost overruns or abandonments that are passed on to ratepayers. The only witnesses to offer testimony suggesting that contracts longer than ten years harm ratepayers were Duke's Witnesses. In fact, the ratepayer advocate's own Witness Horii convincingly rebutted the Companies' Witnesses by stating that "**there is no overpayment risk because future solar will be evaluated based on avoided cost rates that exist at that time in the future**."[188] It is also worth noting that ratepayer-intervenors Wal-Mart and SCEUC were both represented in these hearings and did not put forth any testimony or evidence opposing terms of PPAs greater than ten years. Further, much of Duke's testimony regarding longer term contracts was in the context of the North Carolina Competitive Procurement

[185] Hearing Vol. 1 at 324.5-6 (Chilton Direct).
[186] *Id*. at 324.9.
[187] Power Advisory Report at 34.
[188] Hearing Vol. 2 at 528.9 (Horii Surrebuttal).

of Renewable Energy Program ("CPRE"). Duke's discussion of 20-year CPRE contracts demonstrated that these longer-term fixed contracts – at rates higher than those proposed by Duke in this proceeding – are appropriate and beneficial to customers. Duke Witness Brown testified that 20-year contracts under the CPRE program are in the interest of ratepayers, for two reasons. First, CPRE contracts are at or below the 20-year avoided cost rates. Second, these contracts give the utility limited curtailment rights that Duke "can utilize to optimize the system economically."[189] CPRE contracts allow 10% dispatch in DEP and 5% dispatch in DEC.[190] Additional curtailment is compensated.[191] Witness Holeman, Duke's Vice President of System Planning and Operations, offered further testimony about the operational benefits of contracts with limited dispatch rights.[192]

Witness Brown also testified that a benefit of CPRE-style procurement is that a defined volume of projects are able to contract under the program.[193] Mr. Brown has previously testified to this Commission, and affirmed at the hearing, that contracts with these provisions are in the interest of ratepayers.[194] As confirmed by Duke during the evidentiary hearing, the "all-in" (energy and capacity, averaged across all time periods of production) rate at which winning CPRE projects contracted is $37.75 for DEC and $38.81 for DEP.[195] Duke Witness Brown's support of these contracts was not deterred by the fact – confirmed by Witness Brown – that CPRE projects may go online as late as July 2021.[196]

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[189] Hearing Vol. 1 at 81:18-22.
[190] Hearing Vol. 1 at 84:10-25.
[191] *Id*. at 85:1-20.
[192] Hearing Vol. 2 at 772:15-773:18, 775:20-776:6.
[193] Hearing Vol. 1 at 82:12-18.
[194] *Id*. at 82:19-22.
[195] *Id*. at 93:20-25.
[196] *Id*. at 94-95.

Based on the evidence presented by the Parties, the Commission concludes that it is appropriate for Duke to offer contracts that are longer than ten years, and that there are at least two constructs for contracts longer than ten years that would be consistent with Act 62 by further promoting the development of solar QFs, without imposing undue risks on ratepayers. The proposals offered by intervenors SCSBA and JDA in their Joint Proposed Order are appropriate and comply with the requirements of Act 62, and the Commission adopts them, as described below.

The Commission first notes that the Companies have incorrectly asserted that a specific time limitation applies to when intervenors were required to make such filing under the Act or that a "cutoff" date existed for a proposal to be offered. There is no time limitation imposed in the statute as to when intervenors must, in a proceeding, make a proposal, and if the legislature had intended to impose such a limitation, it could have done so.[197] The plain language of the statute is as follows:

> The commission may also approve commercially reasonable fixed price power purchase agreements with a duration longer than ten years, which must contain additional terms, conditions, and/or rate structures **as proposed by intervening parties and approved by the commission**, including, but not limited to, a reduction in the contract price relative to the ten year avoided cost. Notwithstanding any other language to the contrary, **the commission will make such a determination in proceedings conducted pursuant to subsection (A).**

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[197] "The cardinal rule of statutory construction is to ascertain and effectuate the intent of the legislature." *Charleston County Sch. Dist. v. State Budget and Control Bd.,* 313 S.C. 1, 437 S.E.2d 6 (1993). "Under the plain meaning rule, it is not the court's place to change the meaning of a clear and unambiguous statute." *In re Vincent J.,* 333 S.C. 233, 509 S.E.2d 261 (1998) (citations omitted). "Where the statute's language is plain and unambiguous, and conveys a clear and definite meaning, the rules of statutory interpretation are not needed and the court has no right to impose another meaning." *Id.* at 233, 509 S.E.2d at 262 (citing *Paschal v. State Election Comm'n,* 317 S.C. 434, 454 S.E.2d 890 (1995)). "What a legislature says in the text of a statute is considered the best evidence of the legislative intent or will. Therefore, the courts are bound to give effect to the expressed intent of the legislature." Norman J. Singer, *Sutherland Statutory Construction* § 46.03 at 94 (5th ed. 1992).

S.C. Code Ann. § 58-41-20(F)(1). The General Assembly enacted a floor as to contract length for fixed price PPAs at ten years. The legislature left it to the Commission to decide what conditions should apply, **as proposed by intervening parties**, for terms of fixed price PPAs in excess of ten years. The intent of Act 62 is clear that renewable energy should be promoted by an accurately calculated avoided cost and a term of contract of a length sufficient to enable development. The Commission also notes that the Companies expressly acknowledged that intervenors proposed terms in this proceeding greater than ten years. During the evidentiary hearing, Duke Witness Brown explicitly agreed that the intervenors were proposing terms in excess of ten years in these proceedings during the following exchange:

> Q: (Goldin) "you would agree that **the intervenors propose, in these proceedings, terms longer than ten years, right?**
> A: (Brown) "That—**that is my understanding.**"[198]

Power Advisory also acknowledged in its report that a number of intervenors argued that "contract lengths longer than ten-years were essential if QFs were to secure regularly-available market-rate financing."[199] The Commission therefore adopts, as appropriately proposed by Intervenors, the following two constructs for contracts longer than ten years.

First, the Commission finds that it would be reasonable to require DEP and DEC to offer to enter into longer "dispatchable" PPAs modeled on the contracts it enters into under the CPRE program. Such PPAs would include the following attributes:

> (1) the utility would have the right to dispatch the output of the solar facility, without compensation, up to a defined percentage of the facility's projected annual output (5% for DEC and 10% for DEP); any dispatch in excess of those amounts would have to be compensated at full avoided cost rates.
>
> (2) the term of the contract would be a minimum of ten (10) years and a maximum of twenty (20) years, at the QF's election;

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[198] Hearing Vol. 2 at 689-690.
[199] Power Advisory Report at 34.

(3) the rates for the purchase of energy and capacity under the contract would be fixed at the ten-year avoided cost rate for Large QFs (as calculated in accordance with this Order). Because the ten-year avoided cost rates are substantially lower than twenty-year rates calculated based on the same inputs, the use of the ten-year rate provides a very significant discount to ratepayers as compared to the full avoided cost rates. Furthermore, the expected decrease in project revenues based on the utility's uncompensated curtailment rights satisfies Act 62's requirement that contracts longer than ten years include "a reduction in the contract price relative to the ten year avoided cost." S.C. Code Ann. § 58-41-20(F)(1).

The dispatch and curtailment provisions of the dispatchable PPA would be substantively identical to the Tranche 2 CPRE contracts Duke has currently proposed in North Carolina.[200] Otherwise the terms and conditions of such contracts would be identical to those approved for the Large QF PPA in this docket (except to the extent those provisions directly conflict with the dispatchability and curtailment provisions of the PPA).

Second, the Commission finds that it would be reasonable to require DEP and DEC to offer to enter into PPAs with a term longer than ten years that provide for a "reset" of avoided cost rates under the PPA after ten years. Specifically, such contracts would be for an initial term of ten years, at ten-year avoided cost rates, as calculated in accordance with this Order. At the conclusion of that ten-year period, the QF would have the right to extend the contract for an additional term of up to ten years, at the QF's election. Rates during the second term of the contract would be adjusted to match the then-current avoided cost rates corresponding to the duration of the second term of the contract (e.g. a QF that elected to extend its contract for seven years would be paid at the seven-year avoided cost rate, using whatever inputs and methodologies were approved by the Commission at that time). This rate "reset" at ten years advances the general assembly's goal of promoting QF generation, while protecting ratepayers from any risk associated with longer-term

[200] All technical requirements for the execution of dispatch instructions would be consistent with the conditions required of CPRE projects.

contracts. Importantly, because such contracts would not have rates fixed for a period of longer than ten years, Act 62's requirement of a reduction in contract price relative to the ten-year avoided cost rate does not apply. Otherwise the terms and conditions of such contracts would be identical to those approved for the Large QF PPA in this docket (except to the extent those provisions directly conflict with the dispatchability and curtailment provisions of the PPA).

V. FINDINGS OF FACT AND CONCLUSIONS OF LAW

1. Act 62's requirement that in deciding issues related to avoided cost, the Commission "shall strive to reduce the risk placed on the using and consuming public," requires the Commission to consider all risks reasonably attributable to, or avoidable by, long-term fixed-rate contracts with small power producers. S.C. Code Ann. § 58-41-20(A). Although such contracts create a modest risk of "overpayment" in the event that actual avoided costs are ultimately lower than contracted rates, they also insulate ratepayers from the corresponding risk that avoided cost rates are higher than expected. In addition, procuring energy and capacity via fixed-rate contracts insulates ratepayers from many of the risks associated with utility-developed generation. Under current circumstances, ten-year fixed-rate contracts under PURPA result in a net reduction of risk to ratepayers. Contracts for terms of longer than ten years can also result in a net decrease in ratepayer risk as compared to a business-as-usual approach to development of utility-owned generation.

2. The Notice of Proposed Rulemaking ("NOPR") issued by the Federal Energy Regulatory Commission in September 2019, and discussed at length by Duke's witnesses, is only a proposed rule, has no legal or evidentiary significance, and has no bearing on the Commission's decision in this matter. Act 62 requires the Commission to comply with "PURPA and the Federal

Energy Regulatory Commission's implementing regulations and orders." S.C. Code Ann. § 58-41-20(A). It does not require consideration of proposed rules.

3. In light of the novelty of many of Act 62's statutory requirements and the expedited time frames under which all parties were working, Duke reasonably complied with the statutory requirement that its "avoided cost filing must be reasonably transparent so that underlying assumptions, data, and results can be independently reviewed and verified by the parties and the commission." S.C. Code Ann. § 58-41-20(J). Nonetheless, it is appropriate to provide additional guidance to ensure greater transparency and integrity in the process going forward, and the Commission will solicit input from interested parties concerning transparency requirements prior to initiating the next avoided cost proceeding. In addition, in the interest of transparency it is important that Large QFs which are eligible only for negotiated rates have reasonable access to information concerning the assumptions, data, and results underlying the utility's calculation of their applicable avoided cost rates, including but not limited to the production profile and resource plan relied on by the utility.

4. It is generally appropriate for the Companies to apply the Peaker Methodology to calculated avoided energy costs in this proceeding. However, as discussed elsewhere in this Order, the Commission finds that DEC's and DEP's proposed avoided cost calculations for both energy and capacity have a number of methodological flaws, such that it would not be appropriate or consistent with Act 62 and PURPA requirements going forward. For purposes of the Standard Offer under review in this proceeding, the Commission concludes that DEC's proposed energy rates (1) do not fully and accurately reflect Duke's avoided costs; (2) are not just and reasonable to the electric consumer of the electric utility and in the public interest; (3) discriminate against qualifying cogeneration and small power production facilities. Consequently the proposed rates,

calculations, and methodologies do not meet the requirements of PURPA and Act 62. DEP's proposed Standard Offer avoided energy rates are reasonable and will be approved.

5. It is generally appropriate for the Companies to apply the Peaker Methodology to calculated avoided capacity costs in this proceeding. However, as discussed elsewhere in this Order, the Commission finds that DEC's and DEP's proposed avoided cost calculations for both energy and capacity have a number of methodological flaws, such that the proposed avoided energy and capacity rates, calculations, and methodologies: (1) do not fully and accurately reflect Duke's avoided costs; (2) are not just and reasonable to the electric consumer of the electric utility and in the public interest; (3) discriminate against qualifying cogeneration and small power production facilities. Consequently the proposed rates, calculations, and methodologies do not meet the requirements of PURPA and Act 62.

6. Duke's proposed seasonal allocation of capacity value relies on unjustifiable assumptions about solar penetration. In addition, Duke's modeling of demand during extreme cold events is methodologically unsound. On consideration of the evidence and arguments of the Intervenors and Duke and the recommendations of Power Advisory regarding seasonal allocation, the Commission concludes that the seasonal allocation proposed by SBA Witness Burgess in his Surrebuttal Testimony most reasonably reflects an appropriate seasonal allocation of capacity in DEP and DEC.

7. The impact of some of these methodological flaws can be precisely quantified based on the evidence and analysis in the record; with respect to others the impact can only be estimated. With regard to Standard Offer rates, on consideration of all the evidence in the record, the Commission finds that the avoided energy rates for DEC proposed by SCSBA Witness Burgess in his Direct Testimony, and the avoided capacity rates for DEC and DEP proposed by SCSBA

Witness Burgess in his Surrebuttal Testimony, are fair, reasonable, accurate, and in the interest of ratepayers. As discussed herein, the Commission will also require Duke to implement a number of methodological changes both in calculating avoided cost rates for Large QFs not eligible for the Standard Offer rates approved in this proceeding, and in calculating avoided cost rates proposed for approval in subsequent proceedings.

8. With regard to most of the issues remaining in dispute concerning the Standard Offer PPA and the Large QF PPA, the Commission, on consideration of all the evidence and testimony in the record, generally agrees with the recommendations made by Power Advisory. Specifically, the Commission concludes that:

a. Material alterations to the Standard Offer PPA (meaning any alterations that might affect project revenues, the operational requirements for the facility, or any other substantive rights or duties of the parties) should apply only prospectively, not retrospectively;

b. Duke's proposed 30-month in-service date for the Standard Offer following avoided cost rate approval should be extended day-for-day for any delays attributable to the in-service date of these interconnection facilities, which Duke has already agreed to for the Large QF PPA;

c. Duke's proposal to require a Facilities Study Agreement ("FSA") as a condition of signing a Large QF PPA should only apply if the QF has received a System Impact Statement from the utility within one year of the Interconnection Request. This will prevent Duke from controlling or frustrating QF development through unreasonable delays in interconnection;

d. Duke should either: (1) provide the System Impact Study within 1 year of interconnection request (or an amount of time that is mutually agreeable between the buyer and seller) or (2) allow an offramp to the QF;

9. However, the Commission disagrees with Power Advisory's recommendation that Duke should not be required to offer a surety bond as a form of performance assurance. The Commission considers surety bonds to be a commercially reasonable form of performance assurance, and on balance, the benefit of the availability of a surety bond for QFs outweighs any risk to the Companies of offering a surety bond. The Commission finds especially persuasive the fact that Dominion has agreed to allow the use of surety bonds for PPA performance assurance and has proposed a surety bond form that is commercially reasonable. The Commission will direct Duke to make the same surety bond form available under its Large QF PPAs.

10. As proposed, the Companies' respective Schedule PP (SC) Purchased Power tariffs, Terms and Conditions for the Purchase of Electric Power ("Standard Offer Terms and Conditions"), and Standard Offer power purchase agreement available to all qualifying cogenerators and small power production facilities up to 2 megawatts in size ("Standard Offer PPA") are not commercially reasonable and are not consistent with regulations and orders promulgated by the Federal Energy Regulatory Commission implementing PURPA. Similarly, the DEC's and DEP's proposed form of power purchase agreement available to small power producer QFs that are not eligible for the Standard Offer ("Large QF PPA") is not commercially reasonable and is not consistent with regulations and orders promulgated by the FERC implementing PURPA, and is not consistent with Act 62's requirements. However, with modifications of certain terms and conditions as described herein, the Standard Offer Terms and Conditions, Standard Offer PPA, and Large QF PPA or DEC and DEP are commercially

reasonable and consistent with PURPA and Act 62. Duke shall be required to make a compliance filing of revised PPA and Terms and Conditions consistent with this Order within 30 days.

11. With respect to the proposed NoC form, the Commission appreciates the parties' willingness to compromise and reduce the number of issues in dispute. With respect to the remaining areas of disagreement, the Commission generally finds the testimony of SBA Witness Levitas persuasive, and agrees with Power Advisory that, as proposed, the Companies' NoC Form is not commercially reasonable and is not consistent with regulations and orders promulgated by the FERC implementing PURPA or with Act 62's requirements. However, with modifications of certain terms and conditions as recommended by Mr. Levitas, the NoC Form is commercially reasonable and consistent with PURPA and Act 62. Duke shall be required to make a compliance filing of a revised NoC Form consistent with this Order within 30 days.

12. The standard offer, avoided cost methodologies, form contract power purchase agreements, commitment to sell form, and other terms or conditions necessary to implement S.C. Code Ann. § 58-41-20 approved in this docket for DEC and DEP shall take effect in the first billing cycle after the issuance of this Order.

13. It is in the interest of ratepayers to accurately calculate the costs, if any, that are required to integrate QF resources such as solar on DEC's and DEP's systems. However, the integration of significant solar resources onto DEC's and DEP's systems raises complex technical questions that require careful consideration. Act 62 authorizes the Commission to initiate "an independent study to evaluate the integration of renewable energy and emerging energy technologies into the electric grid for the public interest." S.C. Code Ann. § 58-37-60. One purpose of that study will be to "evaluate what is required for electrical utilities to integrate increased levels of renewable energy and emerging energy technologies while maintaining

economic, reliable, and safe operation of the electricity grid in a manner consistent with the public interest." It is expected that this study will generate useful data and information that will be highly relevant to establishing a reasonable integration charge, if one is appropriate.

14. For purposes of this proceeding, solar integration services charges (SISC) of $1.10/MWh (DEC) and $2.39/MWh (DEP) are reasonable for solar small power producers that enter into a PPA or establish a Legally Enforceable Obligation prior to the effective date of avoided cost calculations and methodologies filed in the next DEC / DEP avoided cost proceeding conducted by the Commission. These charges shall not be subject to adjustment during the term of the PPA. The SISC in the foregoing amounts should apply prospectively only to projects subject to the avoided cost methodologies and contractual terms and conditions established in this proceeding, and shall not apply to the rates established in prior avoided cost proceedings; nor shall it be binding with respect to any subsequent avoided cost proceeding. To the extent the Companies propose to impose the SISC for any other programs or contexts in South Carolina, the Commission will separately consider the appropriateness and applicability of the SISC in the proceedings to consider and review those programs.

15. Duke cannot impose the SISC on a solar QF that is a "controlled solar generator," meaning, generally, any solar QF that demonstrates that its facility is capable of operating, and contractually agrees to operate, in a manner that materially reduces or eliminates the need for additional ancillary service requirements incurred by the utility, including but not limited to QFs equipped with battery storage. Duke must to file with the Commission (by Nov. 18), for review and comment, proposed guidelines for QFs to become "controlled solar generators" and thereby avoid the SISC.

16. The Astrapé Study used to calculate the SISC presents novel and complex issues that warrant further consideration. Duke shall submit the study methodology and inputs to an independent technical review and include the results of that review and any revisions in its initial filing in the next avoided cost proceeding. To the maximum extent practicable the independent review of the study methodology shall take into consideration the South Carolina Integration Study called for by S.C. Code Ann. § 58-37-60. This process shall be subject to Commission oversight and comment from interested stakeholders. The parties agree that the work associated with the independent technical review is reasonable and appropriate to effectuate Act 62 compliance.

17. It is in the interest of ratepayers to require Duke to offer contracts with duration longer than ten years, with appropriate conditions. These contracts would, as discussed herein, include: (1) a dispatchable PPA with a term of up to 20 years, and (2) a PPA with an initial term of ten years at the ten-year avoided cost rate, with an option for the QF to renew for a further period of up to ten years at then-current avoided cost rates. The Commission's ruling on this issue shall not bar any Intervenor or future Intervenor in avoided cost proceedings from proposing, at a later date, other concepts for PPAs with terms longer than ten years.

IT IS THEREFORE ORDERED THAT:

1. The Commission approves the following capacity rates for the DEP and DEC Standard Offer:

<u>*Rate Summary Table – Capacity (SBA Proposed – Revised Seasonal Allocation)*</u>

<u>*DEC*</u>

Season	Summer	Winter	Winter
Period	PM	AM	PM
Allocation	58%	32%	11%
10-Yr Rate (cents/KWH)	16.35	6.07	2.02

<u>*DEP*</u>

Season	Summer	Winter	Winter
Period	PM	AM	PM
Allocation	4%	72%	24%
10-Yr Rate (cents/KWH)	1.94	23.84	7.95

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2. The Commission approves the Standard Offer avoided energy rates proposed by DEP. With respect to DEC, the Commission approves the pricing periods and rates proposed by SBA Witness Burgess.

3. For Large QFs not eligible for standard offer rates, and in future avoided cost proceedings, DEC and DEP shall calculate avoided costs using the peaker method as proposed in its filings, with the following modifications:

   a. For purposes of calculating avoided energy rates, DEC shall use the pricing periods proposed by SCSBA Witness Burgess.

   b. For purposes of calculating avoided capacity rates:

i. The resource plan used to calculate avoided capacity rates shall be revised to reflect the accelerated retirements of Allen Units 4 and 5 and Cliffside Unit 5 (for DEC); and Mayo Unit 1 and Roxboro Units 3 and 4 (for DEP).

ii. DEC and DEP shall follow the seasonal allocation of capacity proposed by SCSBA Witness Burgess, as described in this Order.

iii. Duke shall use the midpoint of an advanced CT and a combined cycle unit (similarly based on EIA inputs).

iv. Duke shall use the seasonal allocation of capacity proposed by SCSBA Witness Burgess.

v. DEC's avoided capacity costs should be adjusted to reflect a one-year acceleration of the year in which capacity is first required to 2025, to reflect the accelerated retirement of coal plants as discussed herein.

vi. To the extent that any near-term market capacity purchases can be avoided prior to 2025, these should be reflected in DEC's avoided cost calculation.

The utility shall, upon request, provide to such Large QFs information reasonably necessary to evaluate the assumptions, data, and results underlying the utility's calculation of their applicable avoided cost rates, including but not limited to the production profile, resource plan, and natural gas cost projections relied on by the utility.

4. In addition to the methodological changes noted above, Duke shall incorporate the following additional methodological changes in avoided cost calculations conducted in future avoided cost dockets conducted under S.C. Code Ann. § 58-41-20:

a. Duke shall endeavor to use the most up-to-date information concerning its resource plan in support of its avoided cost calculations. Duke must also include detailed information about the resource plan relied on in its initial filings, so that Intervenors have adequate opportunities to evaluate the assumptions in that plan.

b. For purposes of calculating avoided energy rates:

   i. Duke shall incorporate a hedging value for solar.

   ii. To address potential differences in avoided energy rates in DEP West and DEP East, DEP shall include a quantitative demonstration, including but not limited to a locational sensitivity analysis, to determine whether its approach to this issue impacts avoided energy costs.

c. For purposes of calculating avoided capacity rates:

   i. In the event Duke seeks to revise its seasonal allocation of capacity, Duke shall provide further empirical support for its assessment of demand during extreme cold weather events.

5. In future avoided cost dockets conducted pursuant to S.C. Code Ann. § 58-41-20, Duke shall provide the following information with its initial filing, or promptly on request of any other Party (subject to appropriate confidentiality protections):

a. Detailed descriptions of must-run and cycling restrictions and the rationale for including these;

b. Hourly data on when must-run units are operating;

c. Hourly data on pumped hydro dispatch in the base case and change case; and Hourly data on the timing of individual unit starts;

d. Detailed analytical information in support of its selection of pricing periods;

e. A quantitative demonstration, including but not limited to a locational sensitivity analysis, to determine whether its calculation of a single set of avoided cost values for the DEP-East and DEP-West BAAs impacts avoided energy costs;

In addition, Duke shall, at the request of any other Party to such proceedings, conduct and share the results of sensitivity analyses and/or modeling runs reasonably necessary to quantify or otherwise ascertain the impact on rates of Duke's underlying methodologies or assumptions.

6. The Commission approves as reasonable and consistent with applicable law the Partial Settlement entered into by Duke, SCSBA, JDA, and CCL and SACE on October 21, 2019. Consistent with the terms of that settlement:

a. Duke is authorized to impose solar integration services charges (SISC) of $1.10/MWh (DEC) and $2.39/MWh (DEP) on solar small power producers that enter into a PPA or establish a Legally Enforceable Obligation prior to the effective date of avoided cost calculations and methodologies filed in the next DEC / DEP avoided cost proceeding conducted by the Commission.

b. Within two weeks of the date of this Order, Duke shall file with the Commission, for review and comment, proposed guidelines for QFs to become "controlled solar generators" and thereby avoid the SISC.

c. Duke shall submit the Astrapé study methodology and inputs to an independent technical review and include the results of that review and any revisions in its initial filing in the next avoided cost proceeding.

d. Within 90 days of the date of this Order the Commission will open a docket pursuant to S.C. Code Ann. § 58-37-60 in which to initiate an independent study to evaluate the integration of renewable energy and emerging energy technologies into the electric grid for the public interest. Any review or revision of the Astrapé study or any other study relied on by Duke to quantify integration costs shall, to the maximum extent practicable, take account of and be coordinated with the independent study referenced in this Order.

7. DEC and DEP shall, within 15 days of the date of this Order, file for Commission approval revised versions of their Standard Offer Power Purchase Agreements, Terms and Conditions; Large QF Power Purchase Agreement, and NoC Form consistent with the requirements of this Order.

8. Duke shall make a commercially reasonable form surety bond, substantially similar to the form used by DESC, available under its Large QF PPAs.

9. DEC and DEP shall, within 60 days of the date of this Order, file for comment and approval standard form PPAs with terms longer than ten (10) years, in accordance with this Order. The parties are encouraged to meet and confer concerning the precise terms of these PPAs prior to any filing.

SO ORDERED.

Respectfully submitted this 8th day of November, 2019.

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